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BIOMASS UTILIZATION STUDY
QUEEN CHARLOTTE ISLANDS, B.C.

FINAL REPORT

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B.C. Hydro and Power Authority

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EXECUTIVE SUMMARY

The prime purpose of this study is to review the present means of supplying power to the B.C. Hydro system on the Queen Charlotte Islands, and to consider the potential and cost of supplying the present and future power requirements utilizing indigenous biomass resources. In May 1983, B.C. Hydro completed an in-house study "Queen Charlotte Islands Power Study - Preliminary Evaluation". The use of wood waste to fire a small thermal generating station, either through a conventional steam or wood gasification system, appeared to warrant further investigation.

With joint funding provided by Energy, Mines and Resources Canada, under the Remote Community Demonstration Program, B.C. Hydro carried out this prefeasibility level evaluation of the utilization of biomass for power generation on the Queen Charlotte Islands. This study is intended to assess the technical and economic feasibility of using indigenous biomass resources to displace oil for remote community power generation. The Queen Charlotte Islands are being used within B.C. Hydro to represent a typical remote community situation for alternative energy studies where power is presently supplied from diesel electric generating stations and integration is unlikely in the near future.

Diesel fuel is currently available on the Queen Charlotte Islands at a cost of 35.1¢/L (June 1984 dollars). It has been assumed that diesel fuel prices will increase at the rate of 1 percent per year (net of inflation) to 38.6¢/L in 1994/95. Thus, the representative total unit energy cost of diesel generation has been determined to be 155 mills/kW·h and 165 mills/kW·h for 1984/85 and 1994/95, respectively, in June 1984 Canadian dollars.

A wood waste availability and cost assessment was carried out by the Forest Engineering Research Institute of Canada (FERIC), in cooperation with MacMillan Bloedel (the main logging operator on Graham Island), to determine the amount of present and future biomass available as forest residues at the landings and roadsides, and as logging residue at the land sorts. Other sources of biomass fuel such as unmerchantable timber and driftwood have not been found to be suitable fuel sources due to the added cost of harvesting, or in the case of driftwood, the detrimental effects of sand and salt trapped in the wood. Peat has been considered qualitatively as a supplement to the wood residue fuel resource.

To attain a power demand sufficient to allow consideration of installation and operation of wood waste generated power, it is assumed that the new plant would service the majority of the electrical load on the Queen Charlotte Islands. This would require connection of the Sandspit and Masset generating systems by a 69 kV transmission line. It is assumed that the existing diesel generation stations would be retained as standby generating stations and used for peak load generation as the demand grows.

A conventional small biomass-fired thermal generating station concept has been developed. The new 10 MW centralized generating station is designed to supply all the near-term forecast load, exclusive of new industrial demand, for the Queen Charlotte Islands.

The thermal generating station design has been based on supplying 45.54 GW·h of electricity to meet a peak demand of 9.47 MW in 1994/95. The conventional wood-fired thermal generating station is commercially available and would be the most suitable plant for supplying reliable power at such a remote location. The base case plant is developed using two 5 MW packaged wood-fired boiler plants, although comparable plant capital costs were estimated for using a single 10 MW package or five 2 MW packages.

Basic plant design parameters, layout and offsite facilities were developed within B.C. Hydro. Particular design details, specifications, and cost estimates were provided by outside consultants.

A biomass gasification power generation status review is included as part of this study to determine a timeframe for commercial application of the technology. The wood gasification power generation technology is not expected to be commercially available to the same degree as the conventional steam boiler system for another 5 to 10 years. However, a conceptual design was prepared based on using the Imbert gasifier-gas engine system commercially available from Germany. The 10 MW station is based on 15 identical gasifier-engine generator power trains, rated at 685 kW each.

A detailed cost estimate was prepared based on a conventional thermal generating station at Ferguson Bay. Wood fuel preparation, site development and off-site facilities are included in the estimate. The cost estimate for the wood gasification power generation option was developed from the base case thermal station. An economic evaluation was carried out to compare the wood-fired thermal generating station options with the costs of the present diesel electric generating system. Although the unit energy costs for wood gasification power generation is not significantly higher than conventional thermal generation the technology is not sufficiently advanced nor reliable enough for consideration at this time.

No significant socio-economic or environmental impacts are expected from construction and operation of the thermal generating station. Environmental impacts from the thermal plant will be kept at or below the minimum standard levels for such plants. This will be achieved through good plant design and efficient operating procedures.

Construction activities will have some impacts on the terrestrial environment. However, since the site is adjacent to the existing logging and land sort operation these impacts will be minimal. Construction of the thermal plant will not disturb any known heritage sites. There is a midden of charcoal and crushed shells on the MacMillan Bloedel property nearby but this would not be affected.

A project of this size will certainly have some social and economic impacts, particularly in the Port Clements area. While the construction forces, and later the operating and maintenance crews, will not be large they will still represent a significant percentage increase in the present local population. The impact should be positive with some increased employment opportunities.

A computer program developed by B.C. Hydro was used for comparing the energy costs of the two wood-fired thermal power generation options. Since the cost of delivered wood waste to the station is the most sensitive variable in the operation of the thermal generating station, various fuel supply cost scenarios were tested.

The unit energy cost of power produced by a wood-fired thermal generating station was found to range from 112 mills/kW·h for low cost fuel at $31.10/ODt to 245 mills/kW·h for the high cost fuel at $153.46/ODt. The base case assumes that a blend of wood fuel could be made available, including some low grade pulp wood, at a cost of $100.40 resulting in a unit energy cost of 187 mills/kW·h (excluding additional transmission required to connect the Masset and Sandspit grids).

It was determined that the break even cost for wood waste, to match the cost of diesel generation at 165 mills/kW·h (1994/95), was $61.33/oven-dried tonne (ODt) (June 1984 Canadian dollars). The effect of a 20 percent grant (based on capital cost) for plant construction under the Forest Industry Renewable Energy (FIRE) Program would be to increase the break even wood fuel supply cost to $67.41/ODt. MacMillan Bloedel have indicated that low grade pulp wood could be supplied at about $100/ODt resulting in a blended fuel cost of $80/ODt. This cost is considered to be within a negotiable range for further evaluation and they are interested in further discussions regarding the wood fuel delivery.

A third party has indicated an interest in participating in a feasibility study and the detailed design of a 10 MW thermal generating station. They would also be interested in participating in the construction and operation of the station if it was found to be economically justified.

Based on this Study, it is recommended that:

1. a detailed station design and feasibility study be carried out for the siting of a 10 MW conventional wood-fired thermal generating station on the Queen Charlotte Islands;

2. a consultant capable of designing, construction and operating the station be solicited and participate in the design study; and,

3. funding be considered under the Phase II Enerdemo, Canada, Program.

SECTION 1.0 - INTRODUCTION

1.1 BACKGROUND

B.C. Hydro is a provincial Crown Corporation whose mandate is to supply electricity and gas at the lowest long-term price to British Columbia customers. B.C. Hydro generates, transmits and distributes electricity to more than 90 percent of British Columbia's population, and distributes gas to customers in the lower Mainland and Victoria areas. Most of the electricity comes from hydroelectric plants and the majority of the customers are served by an interconnected, province-wide system of transmission lines. Remote communities not connected to the main transmission lines are served by small local diesel generating stations.

B.C. Hydro supplies power to 14 remote communities in British Columbia from diesel generating stations. Two of the larger of these diesel generating stations are located at Masset and Sandspit, and supply electricity to the Queen Charlotte Islands (Fig. 1-1).

The Queen Charlotte Islands are a series of more than 150 small and large islands, actually the tops of a submerged ridge, lying at the western edge of the continental shelf 90 km west of the British Columbia mainland. The Charlottes for the most part are a spectacular, virgin wilderness. The triangular-shaped archipelago, which is about 250 km long and 84 km across at its widest point, is dominated by two islands - Graham Island in the north and Moresby Island in the south.

The western shoreline is rugged and rock-girded, interspersed on Graham Island by countless sand-beached bays that contrast with the almost impenetrable wall presented by Moresby Island. To the north and east on

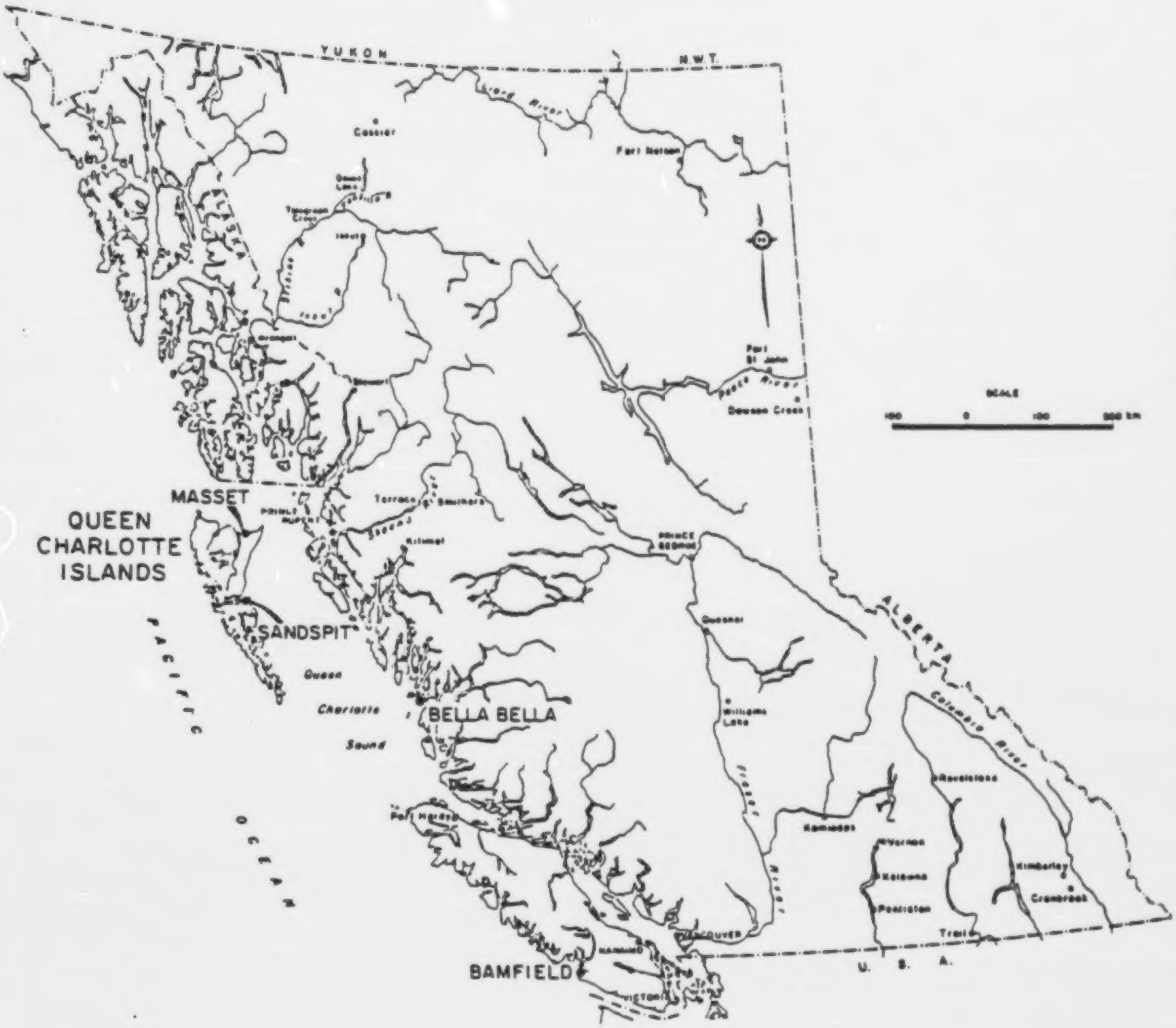


Figure I-1

LOCATION MAP
QUEEN CHARLOTTE ISLANDS

Graham Island the high land blends into extensive reaches of muskeg and peat bog. Further to the east broad sandy beaches face Hecate Strait, a fairly shallow body of water that separates the Charlottes from the mainland.

The economic life blood of the islands has been, and still is, logging. Although the islands have a relatively small land area, (905 944 ha) they hold approximately 8 percent of the British Columbia timber resource. Several large companies, including MacMillan Bloedel, Crown Forest Products, Rayonier, and Cipa have large tree farm licences and maintain large logging operations spread throughout the islands.

B.C. Hydro presently supplies electricity to the Queen Charlotte Islands from two diesel generating stations, one located near Sandspit and the other near Masset. The recent escalating cost of diesel fuel has increased the cost of energy produced by these generating stations to the point where alternative fuels and other methods of power generation may now be feasible. In May 1983, B.C. Hydro completed an in-house study, "Queen Charlotte Islands Power Supply - Preliminary Evaluation". The purpose of this study was to review the present means of supplying power to the B.C. Hydro system on the Queen Charlotte Islands and to consider the potential and cost of supplying the present and future power requirements from alternative sources of energy. The study recommended that tidal, small hydroelectric, wind and wood waste-fired thermal power generation warranted further investigation. B.C. Hydro has already initiated studies into the feasibility of wind and tidal power generation.

1.2 STUDY OBJECTIVES

This study is intended to assess the technical and economic feasibility of utilizing indigenous wood waste resources to displace oil for remote community power generation. The Queen Charlotte Islands are being used within B.C. Hydro to represent a typical remote community situation for alternative energy studies, where power is presently supplied from diesel electric generating stations and integration is unlikely in the near future.

The objective of this study is to:

- assess the biomass availability and determine the cost of fuel,
- evaluate the suitability of a site in the Ferguson Bay area,
- prepare a detailed conceptual design and cost estimate of a small biomass-fired conventional thermal generating station,
- evaluate the wood gasification power generation concept and prepare a cost estimate,
- identify and discuss environmental and socio-economic impacts, and
- evaluate the economics of utilizing biomass for power generation on the Queen Charlotte Islands.

A wood waste availability and cost assessment has been carried out by the Forest Engineering Research Institute of Canada (FERIC), in cooperation with MacMillan Bloedel (the main logging operator on Graham Island), to determine the amount of present and future biomass available as forest residues at the landings and roadsides, and as logging residue at the land sorts. Other sources of biomass fuel such as unmerchantable timber and driftwood have not been found to be suitable fuel sources due to the added cost of harvesting, or in the case of driftwood, the detrimental effects of sand and salt trapped in the wood. Peat has been considered qualitatively as a supplement to the wood residue fuel resource.

A preliminary site evaluation has been carried out to determine the suitability of a centralized plant site near Ferguson Bay. To attain a power demand sufficient to allow consideration of installation and operation of wood waste generated power, it is assumed that the new plant would service the majority of the electrical load on the Queen Charlotte Islands. This would require connection of the Sandspit and Masset generating systems by a 69 kV transmission line. It is assumed that the existing diesel generation stations would be retained as standby generating stations and used for peak load generation as the demand grows.

A conventional small biomass-fired thermal generating station concept has been developed. The new 10 MW centralized generating station is designed to supply all the near-term forecast load, exclusive of new industrial demand, for the Queen Charlotte Islands. Wood residue collection and fuel processing facilities were included in the design to meet the requirements of the station. Basic plant design parameters, layout and offsite facilities were developed within B.C. Hydro. Particular design details, specifications, and cost estimates were provided by outside consultants.

For this study a wood gasification power generation concept was developed. The new 10 MW centralized generating station is also designed to supply all the near-term forecast load, exclusive of new industrial demand, for the Queen Charlotte Islands. Included in the design are wood residue collection and fuel processing facilities to meet the requirements of the station.

Since generation of power using low-Btu gas fuel produced by biomass gasification is still not a fully proven technology, a commercial or demonstration stage of development is needed before proceeding with a detailed design. A biomass gasification power generation status review is included as part of this study to determine a timeframe for commercial application of the technology.

A cost estimate was prepared based on the Ferguson Bay conventional thermal generating station site development and off-site facilities together with cost figures for a suitable gasifier-engine generator system. An economic evaluation was carried out to compare the wood-fired thermal generating station options with the costs of the present diesel electric generating system. The costs and data developed should also be useful in evaluating other potential sites in the non-integrated system where there is an indigenous biomass energy source.

1.3 EXISTING SYSTEM

As of June 1984, the B.C. Hydro generating system on the Queen Charlotte Islands consists of two diesel-powered generating stations (DGS) that are not interconnected by distribution lines. For determining the firm generating capability of a diesel generating station, it is B.C. Hydro policy to have sufficient capacity available to meet the peak load with the largest generating unit out-of-service. Diesel fuel is supplied to both diesel generating stations by tank truck from a bulk fuel station at Skidegate. Fuel is delivered to Skidegate by barge from Vancouver, B.C.

The largest station is situated near Masset and contains the following generating units:

3 x 2100 kW (ALCO)	6300
1 x 2500 kW (EMD Mobile)	2500
1 x 600 kW (CAT Mobile)	600
Total Generating Capacity	9400
Firm Generating Capability	6900

The basic diesel generating station at Masset consists of three 2070 kW Alco (Montreal Locomotive) stationary diesel generating units located in a main powerhouse. Difficulties were experienced with early operation and reliability of the Alco units requiring that additional mobile generating equipment be installed on-site. The 2500 kW EMD (General Motors - Electromotive Division) diesel generating unit, is a self-contained portable skid-mounted unit able to provide this added security. A 600 kW Cat (Caterpillar) road-mobile diesel generating unit is maintained on-site to provide a smaller increment of power generation.

The Masset DGS supplies electricity to the community of Masset, the military base and the village of Haida. The station also supplies power to the Port Clements area by means of a 3-phase 25 kV distribution line. The peak load for the Masset DGS in 1983/84 was 3.61 MW and a total of 19.27 GW·h of electricity was generated at an average load of 2.20 MW [Diesel Apparatus Section, Monthly Production Report, March 1984].

The second station is situated at Sandspit and contains the following generating units:

2 x 1000 kW (Cooper)	2000
2 x 600 kW (Cooper)	1200
1 x 500 kW (CAT)	500
1 x 2500 kW (EMD Mobile)	2500
2 x 600 kW (CAT Mobile)	1200
Total Generating Capacity	7400
Firm Generating Capability	4900

The basic diesel generating station, at Sandspit, consists of a powerhouse containing two 1000 kW and two 600 kW Cooper (Cooper Bessemer) stationary diesel generating units, and one 500 kW Cat (Caterpillar) stationary diesel generating unit. A 2500 kW EMD (General Motors - Electromotive Division) self-contained portable skid-mounted diesel generating unit and two 600 kW Cat (Caterpillar) road mobile diesel generating units have been added to meet the growing electrical demand.

The Sandspit DGS supplies electricity to the community of Sandspit and the airport. The station also supplies power to Queen Charlotte City and the village of Skidegate, by means of a 3-phase, 25 kV submarine cable across Skidegate Inlet. A single-phase, 25 kV distribution line supplies electricity to the Tlell area as shown on Fig. 3-1.

The peak load for the Sandspit DGS in 1983/84 was 3.7 MW and a total of 18.23 GW·h of electricity was generated at an average load of 2.08 MW [Diesel Apparatus Section, Monthly Production Report, March 1984].

The cost of diesel power increased dramatically in the last several years because of the escalating cost of crude oil. In March 1976 the average cost of diesel fuel purchased by B.C. Hydro was approximately $0.112/L and rose steadily thereafter to a cost of approximately $0.363/L in September 1982. Corresponding increases were from $0.107/L to $0.380/L for Masset (December 1982) and from $0.114/L to $0.355/L for Sandspit (September 1982).

Since then, a tempering trend has occurred with a subsequent increase in the average cost of diesel fuel to $0.351/L, for both Masset and Sandspit, in June 1984.

World economic recovery is expected to increase the price of diesel fuel, but these increases will probably be more moderate than in the recent past. World prices of crude oil have decreased during the recession, whereas Canada's selling price has been generally increasing. Future increases in the cost of diesel fuel are expected, and for this report is has been assumed that the cost of diesel fuel will increase at 1 percent per year (net of inflation) to 38.6¢/L (June 1984 Canadian dollars) in 1994/95.

1.4 PRESENT COST OF DIESEL GENERATION

In order to evaluate the economics of alternative generation schemes for the Queen Charlotte Islands, an equivalent cost of the present diesel generating systems has been prepared.

The following assumptions were made in preparing estimates of the cost of diesel generation:

1. Plant sizes remain constant until 1994/95.
2. Maintenance and labor were averaged for the fiscal years 1980/81 to 1983/84 inclusive after inflating the costs for each year to 1 June 1984 dollars using the B.C. Hydro Inflation Factors issued by Strategic Planning effective 12 January 1984. The resulting values were corrected to delete customer related distribution costs by dividing by 1.2828 for Masset and 1.3801 for Sandspit. These same factors were applied to the values available for school taxes in order to estimate the component of these taxes which relate to the generating station.
3. Interest, taxes and depreciation remain at 1982/83 levels, which is the last information that is available.
4. Fuel prices are those which were applicable on the 1st of June 1984.
5. Consumption rates were estimated by determining the mean rates for fiscal years 1980/81 through 1983/84 inclusive.
6. The forecast electrical energy demand for 1994/95 was used in preparing these estimates.

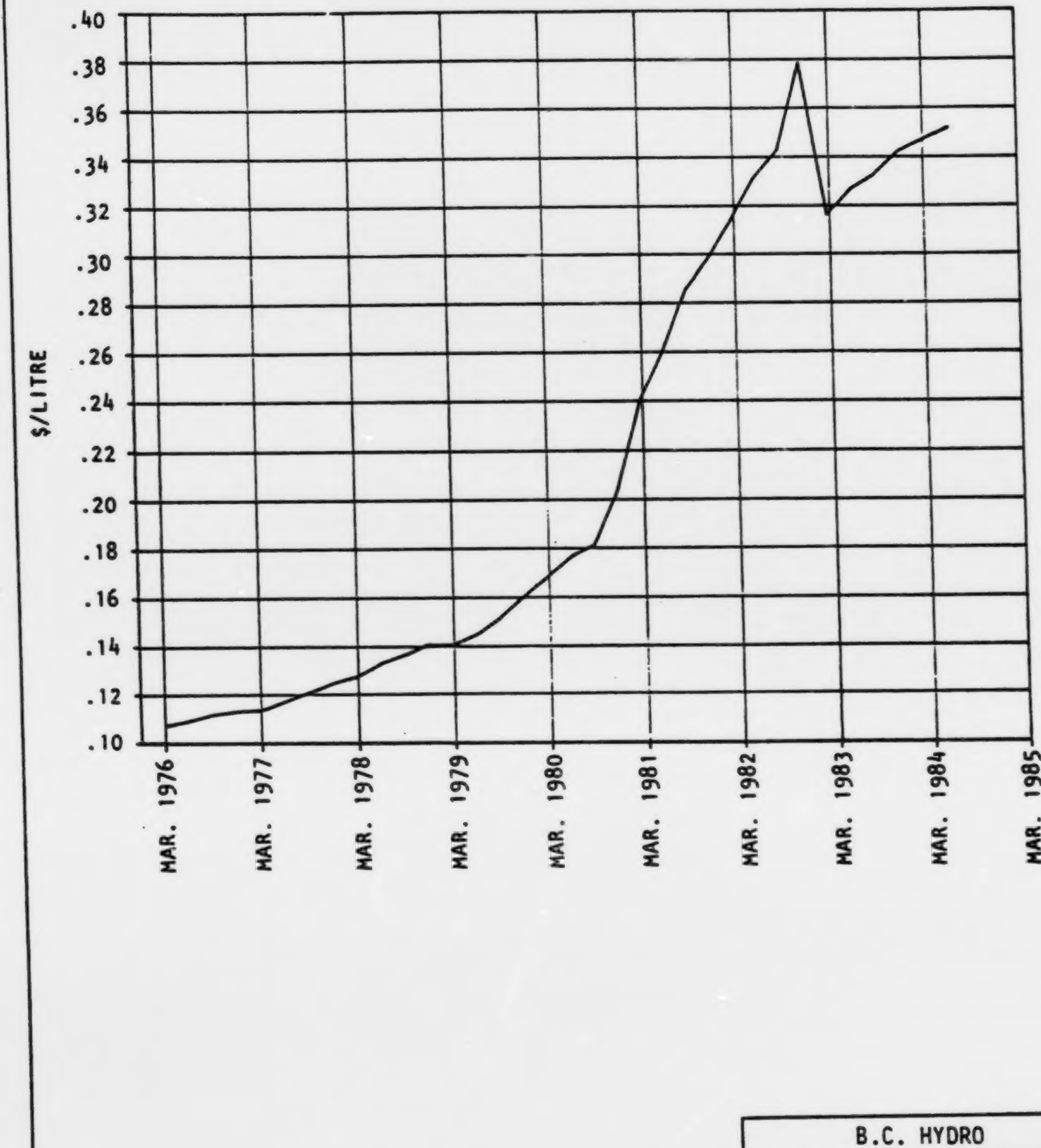
The existing diesel plants burn No. 2 fuel oil which in June 1984 cost $0.351/L (Figs. 1-2 and 1-3). The annual cost of energy from the Masset plant is estimated to be $3.6 million, resulting in a unit energy cost of 155 mills/kW·h. The fuel cost is 67 percent of the cost of energy from the diesel plant at Masset. Similarly, the annual cost of energy from the Sandspit plant is estimated to be $3.4 million, also resulting in a unit energy cost of 155 mills/kW·h. The fuel cost is 68 percent of the cost of energy from the diesel plant at Sandspit. The Summary of Present and Energy Costs for Masset and Sandspit diesel generation is provided in Table 1-1.

1.5 FUTURE LOAD GROWTH

Projections of load requirements for the period 1983/84 to 1994/95 are summarized in Table 1-2. For reference the actual load growth for the Masset and Sandspit systems are shown in Figs. 1-4 and 1-5, with the forecast load requirements for the period 1984 to 1994. On this basis the total power requirements for the Queen Charlotte Islands in the year 1994/95 are 45.54 GW·h, at a peak load of 9.47 MW and an average load of 5.20 MW. Consequently, the thermal plant design has been set at 10 MW with the existing diesel generating stations providing standby and peaking power as required.

Based on the above load forecast, B.C. Hydro has no current plans to add any additional generating facilities to either the Masset DGS or the Sandspit DGS, over the next 10 years. The present installed generating capacity on the Queen Charlotte Islands should meet the forecast load requirements to 1994/95. These estimates assume that there are no increases in industrial load and no substantial increases in residential load due to extensive industrial development.

The MacMillan Bloedel Company presently generates all the power required for its operations and personnel at Juskatla. If a generating station



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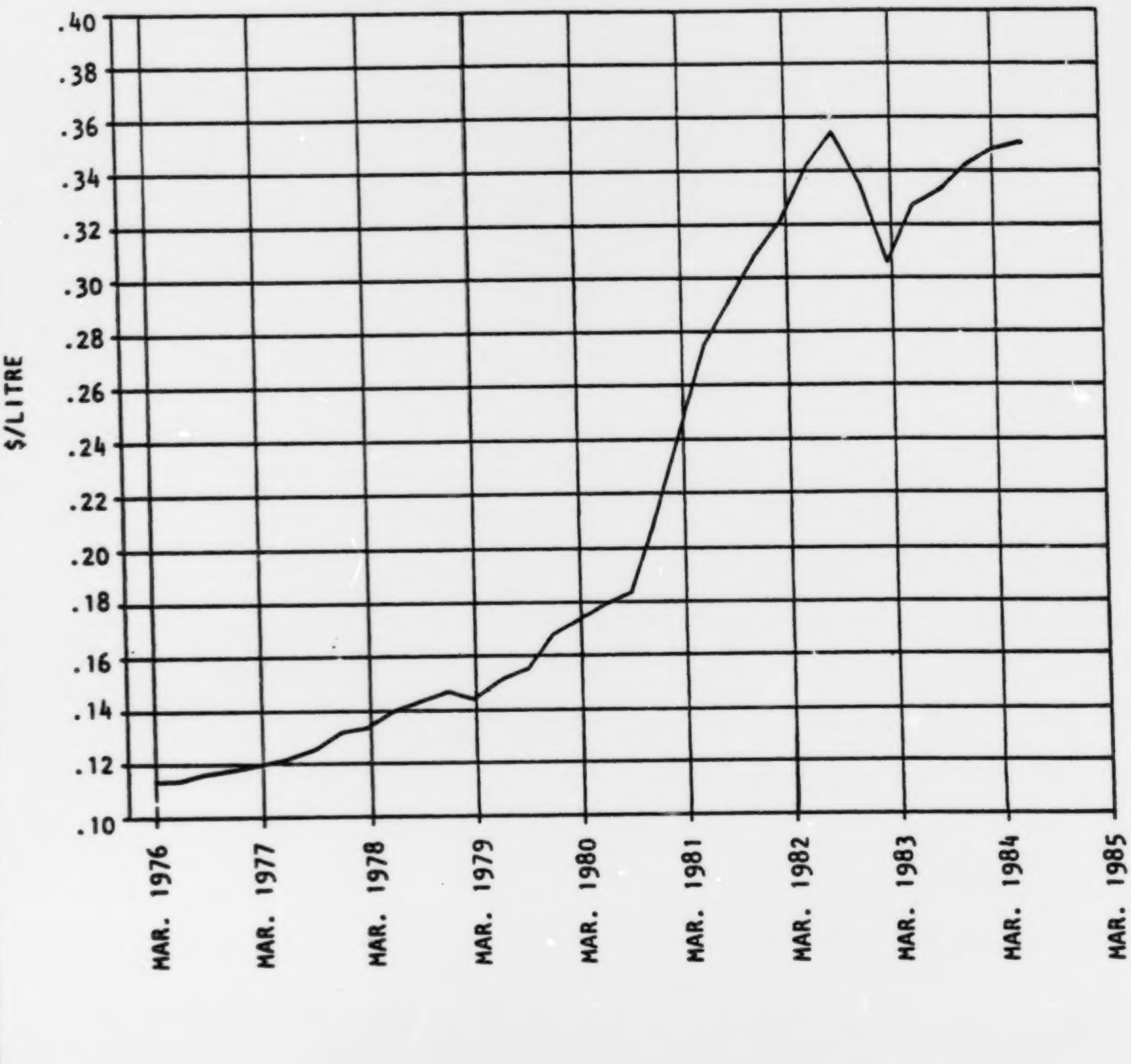
MASSET D.G.S.
AVERAGE COST OF DIESEL OIL,
(INCLUDES TAXES)
DIESEL APPARATUS
FIG 1.2



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SANDSPIT D.G.S.
AVERAGE COST OF DIESEL OIL,
(INCLUDES TAXES)
DIESEL APPARATUS
FIG 1.3

TABLE 1-1

MASSET AND SANDSPIT DIESEL GENERATION SUMMARY OF PRESENT ENERGY COSTS

(June 1984 Canadian Dollars)

	Diesel Generation		
	Masset	Sandspit	Total
Plant Capacity (MW)	9.4	7.4	16.8
Capacity Factor (%)	28	34	
Annual Energy (GW·h) (1994/95 Forecast Load)	23.27	22.27	45.54
Type of Fuel	No. 2 Diesel	No. 2 Diesel	No. 2 Diesel
Cost of Fuel	$0.351/L $8.96/GJ	$0.351/L $8.96/GJ	$0.351/L $8.96/GJ
Construction Period (a)	-	-	-
Plant Life (a)	20	20	20
Distribution Life (a)	30	30	30
Capital Cost (k$)			
Plant Construction (k$)	-	-	
New Distribution Construction Cost (k$)	-	-	
New Substation Construction Cost (k$)	-	-	
Total Construction Cost (k$)	-	-	
Project Cost ($/kW)	-	-	
Total Capital Cost (k$)	-	-	
Annual Costs			
Amortization Cost (k$)	608	464	1072
Operation and Maintenance (k$)	476	575	1051
Taxes (k$)	106	66	172
Fuel Costs (k$)	2415	2336	4751
Total Annual Cost (k$)	3605	3441	7046
Gross Unit Energy Cost (mills/kW·h)	154.92	154.51	154.72

TABLE 1-2

QUEEN CHARLOTTE ISLAND LOAD FORECAST[*1]
1983/84 TO 1994/95

	Masset		Sandspit		Queen Charlotte Islands Total	
	Peak kW	Annual Energy GW·h	Peak kW	Annual Energy GW·h	Peak kW	Annual Energy GW·h
1983/84 (Actual)	3610	19.27	3700	18.23	7310	37.50
1984/85	3800	19.31	3900	17.77	7700	37.08
1985/86	3900	19.82	4090	18.63	7990	38.45
1986/87	3960	20.12	4170	19.00	8130	39.12
1987/88	4020	20.43	4255	19.38	8275	39.81
1988/89	4100	20.83	4340	19.77	8440	40.60
1989/90	4180	21.24	4425	20.16	8605	41.40
1990/91	4260	21.64	4515	20.57	8775	42.21
1991/92	4340	22.05	4605	20.98	8945	43.03
1992/93	4420	22.46	4700	21.41	9120	43.87
1993/94	4500	22.86	4795	21.84	9295	44.70
1994/95	4580	23.27	4890	22.27	9470	45.54

Notes:

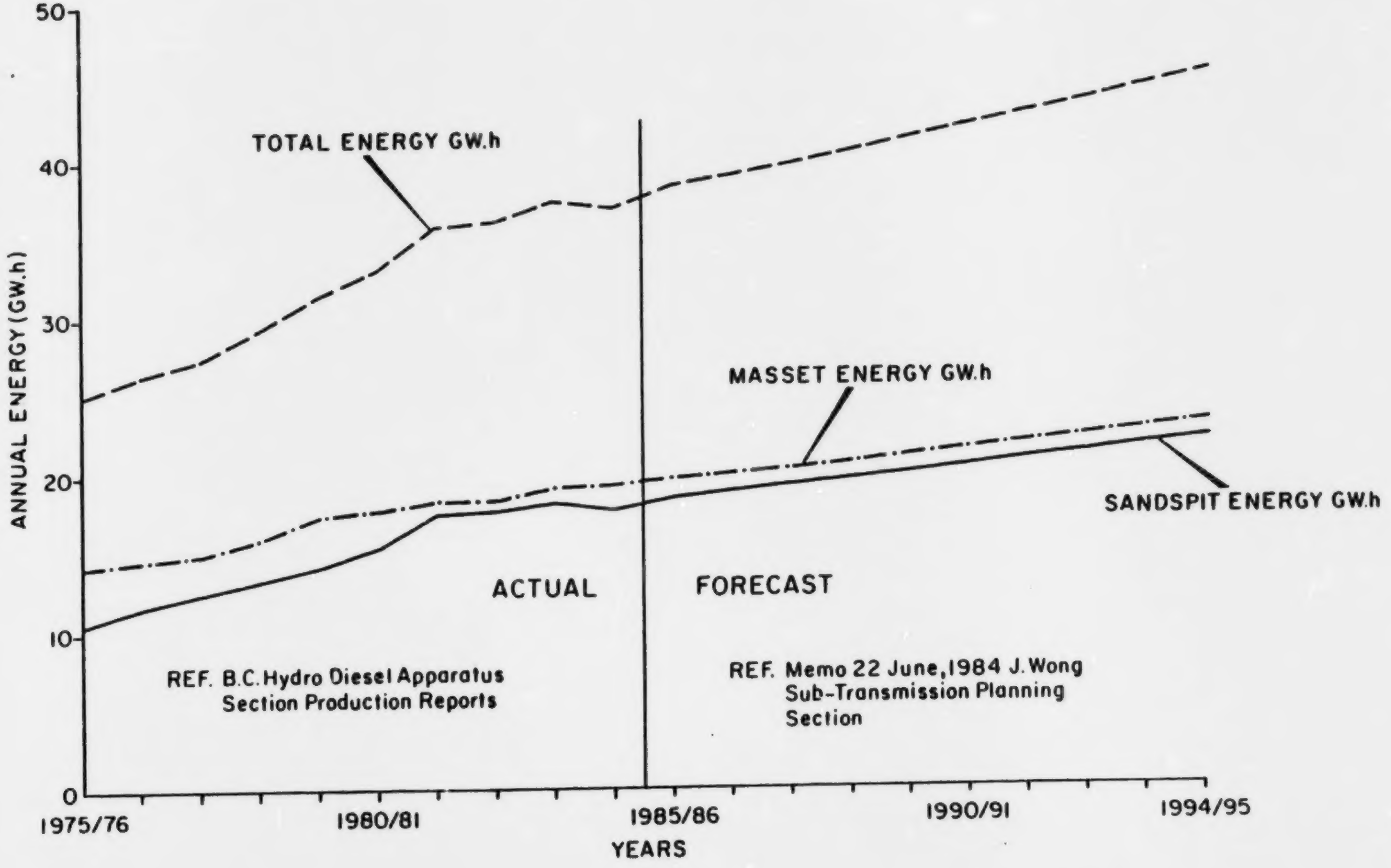
1. The peak demand forecast in kW is preliminary based on verbal advice from J.E. Kearney of 21 June 1984.

2. The annual energy forecast was produced based on the preliminary load forecast and applying an annual load factor of 58 percent for Masset and 52 percent for Sandspit.

[*1] Memo to L.A. Roosdahl from J.S. Wong dated 22 June 1984.

Figure I-4

QUEEN CHARLOTTE ISLANDS
ANNUAL ENERGY CONSUMPTION
1975/76 TO 1994/95

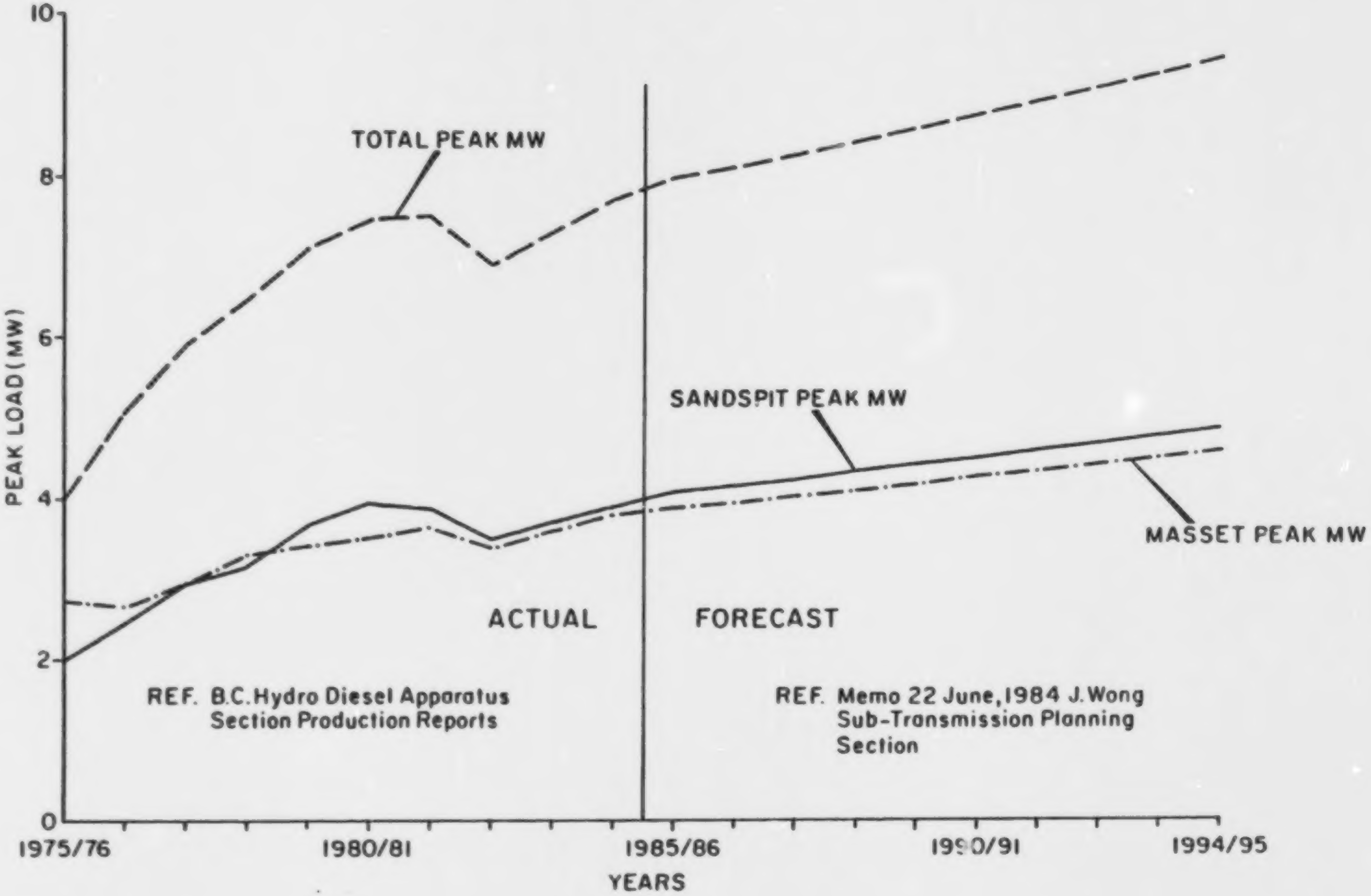


REF. B.C.Hydro Diesel Apparatus
Section Production Reports

REF. Memo 22 June, 1984 J. Wong
Sub-Transmission Planning
Section

Figure I-5

QUEEN CHARLOTTE ISLANDS
ELECTRIC PEAK LOAD
1975/76 TO 1994/95



REF. B.C. Hydro Diesel Apparatus Section Production Reports

REF. Memo 22 June, 1984 J. Wong Sub-Transmission Planning Section is built at Ferguson Bay this electrical load (peak approximately 300 kW) could be tied into the B.C. Hydro system.

Geologically, the Queen Charlotte Islands have a significant mineral potential. There has been a high degree of exploration activity in recent years and some of this activity could result in new mines being developed. New mines could require a substantial amount of power and they could also cause appreciable increases in commercial and residential load.

Major mining developments could alter the current situation by adding industrial load. Consolidated Cinola Mines proposes to develop an open pit gold mine near Port Clements which would require 41 MW of electrical capacity to support the operation. It must be recognized that the planned life of the mine is approximately 15 years based on proposed production figures and current reserves. Reserves, and therefore mine life, may be extended with additional exploration, but this possibility cannot be predicted. B.C. Hydro could not service this large load increase from the existing diesel plants on the Islands or from the proposed biomass-fired thermal generating station.

Consolidated Cinola Mines Limited has conducted pilot plant tests on their gold property 17 km southeast of Ferguson Bay, and is now seeking regulatory approval for development of a $200 million gold mine near Port Clements. This mine would employ in the neighbourhood of 250 people. There is no information on the projected increase of persons residing in Port Clements because of the addition of mine workers, workers' dependents and persons providing additional services. Similarly, there is no information on the increase in peak load at Masset resulting from this influx of persons.

Any industrial demands would require careful study before the B.C. Hydro system is committed to meet such load requirements. Mining developments are subject to fluctuating market conditions and availability of ore, and their operation can be erratic, intermittent and relatively short-lived compared to the operating life of utility projects. The B.C. Hydro system on the Queen Charlotte Islands is relatively small and would require expansion to meet such industrial requirements; therefore, the operating conditions of the comtemplated loads are of more concern on the Queen Charlotte Islands than they would be in mainland locations where the load could be taken from the provincial grid.

A new tourism potential promises the most pronounced increase in economic activity on the Islands. The introduction of car and passenger service to the islands by B.C. Ferries in 1980 was one of the major developments of the century. The lure of the mysterious islands can now be put to good use. Travellers have a convenient and inexpensive means of crossing Hecate Strait from Prince Rupert. Although the islanders were timid about the effect tourists and recreation vehicles would have on their way of life, most now agree that the introduction of 30 000 people during 1982 was barely noticeable. The significance of the tourism potential must be seen in terms of the growing number of visitors to Prince Rupert and the north coast of British Columbia and the spin-off this will create for the Charlottes.

The Provincial and Federal governments recently reached an agreement giving control of offshore oil and gas exploration in the Hecate Strait region to British Columbia. This will, in the near future, result in development of offshore exploration activities. The Provincial government has already set up an office to assist coastal communities with their concerns over offshore exploration. The waters of Hecate Strait are believed to be fertile exploration areas. Some drilling was conducted in the early 1970s but a Federal moratorium implemented shortly afterwards cut short the drilling programs.

It is quite obvious that continued growth and economic expansion will occur on the Queen Charlotte Islands and the time is right to evaluate the best approach for meeting the indicated increased load requirements.

1.6 BIOMASS GENERATING OPTIONS

Biomass-fired thermal generating technologies which are considered to be potentially applicable for electrical generation on the Queen Charlotte Islands include conventional thermal generation (steam boiler-turbogenerators) which use the fuel directly, or indirect-fired generating units which use gaseous or liquid fuels produced by gasifiers. The indigenous biomass resource most readily available as a fuel is wood wastes generated by the logging industry. There is indicated to be sufficient logging residues and low grade pulp logs to fuel a 10 MW thermal generating station without considering harvesting standing timber or using beach logs and driftwood.

Peat is a major indigenous resource on the Islands which could be used as a fuel supply. However, because there is an adequate supply of wood waste available, only a qualitative assessment of the peat resource has been made at this time.

A thermal generating station can be generally defined as one in which the energy of a burning fuel is used, either directly or indirectly, to drive an electric generator. The prime mover could be a steam turbine, a steam engine, an internal combustion engine, or a gas turbine.

This study investigates, as a base case, the conceptual design of a 10 MW biomass-fired conventional thermal generating station, consisting of two 5 MW packaged generating units. Alternative station designs have been created by costing a single 10 MW generating unit and five 2 MW units into the basic station design. All design details and costs have been developed for the base case situation, and have been adapted to suit the alternative station designs.

A review of the status of wood gasifiers and engine generators has been carried out to establish a time frame for commercial application of the gasification power generation technology. For comparative purposes, the base case thermal station design has been adapted to arrive at relative costs and economics for a biomass gasification power generating station.

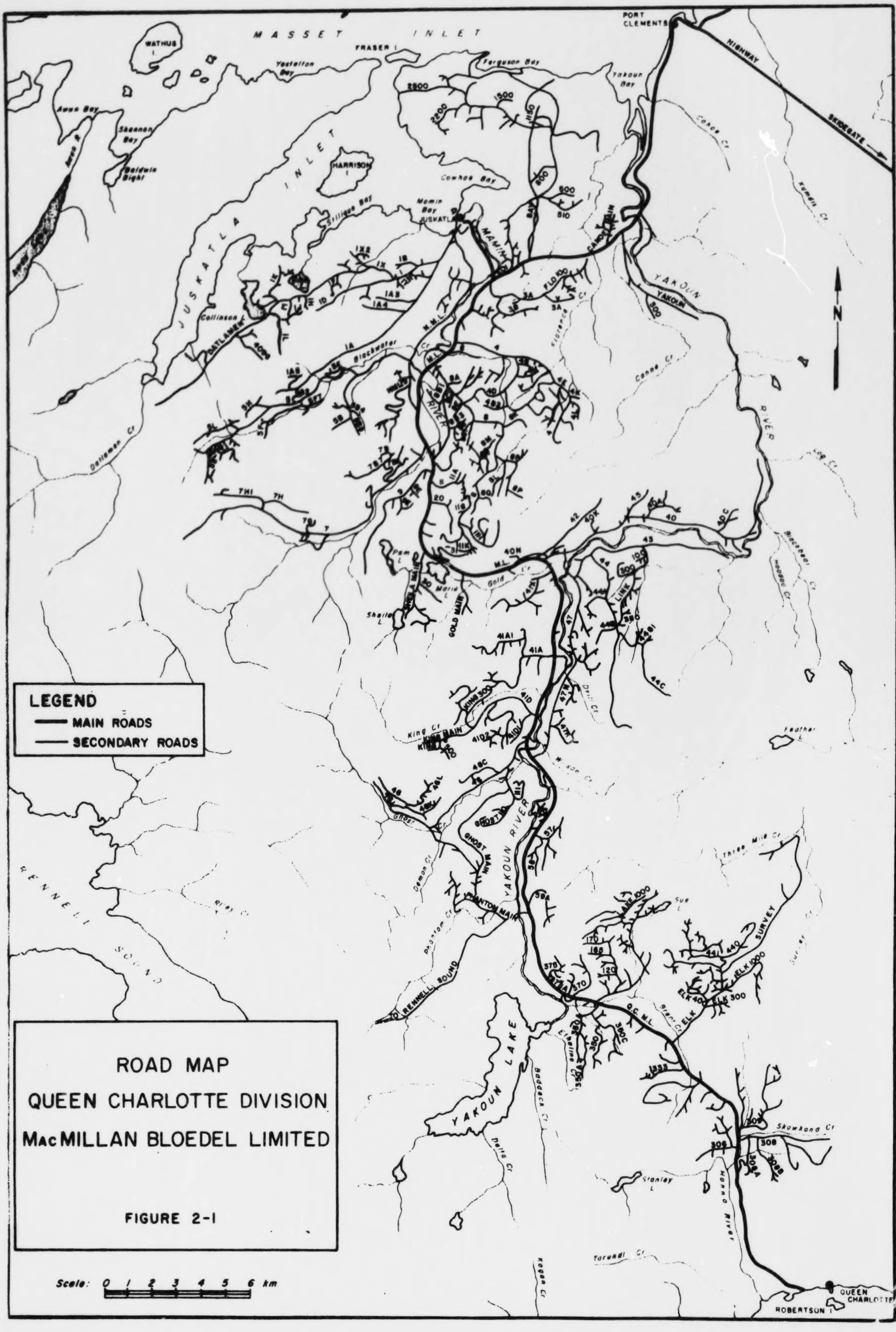
SECTION 2.0 - BIOMASS AVAILABILITY

2.1 DISCUSSION

The MacMillan Bloedel Company Limited has by far the largest timber harvesting program in the Queen Charlotte Islands and accordingly produces most of the wood waste generated on the Islands. Their operation also produces practically all of the waste wood readily available for future commercial use as a source of heat or power by B.C. Hydro because they have extensive licensed areas in the east central region of Graham Island. For the purpose of the biomass availability portion of the study, it has been assumed that a 10 MW wood waste-fired thermal generating station would require 50 000 oven-dried tonnes of wood waste per year as fuel.

The operations of MacMillan Bloedel currently produce 31 950 oven-dried tonnes (ODt) of wood waste annually in their harvesting operations. This waste includes large branches, trees less than 150 mm in diameter, split logs, trees with rotten cores, and cull logs left in the loading areas and beside the logging roads (Figs. 2-2, 2-3 and 2-4).

MacMillan Bloedel and the other logging companies move the marketable logs by truck over an extensive series of logging roads (Fig. 2-1) to land sorts where they are prepared for shipping, loaded on barges, and transported to mainland sawmills (Figs. 2-5, 2-6, 2-7 and 2-8). A further 3825 ODt/a of wood waste is produced during the land sort operation which would also be available as a fuel at minimal cost. The total annual quantity of wood waste produced by MacMillan Bloedel operations is, therefore, 35 775 ODt. The remainder of the wood fuel requirements for the generating station would have to be made up from low grade pulp logs, which are not normally utilized.



ROAD MAP
QUEEN CHARLOTTE DIVISION
MacMILLAN BLOEDEL LIMITED

FIGURE 2-1

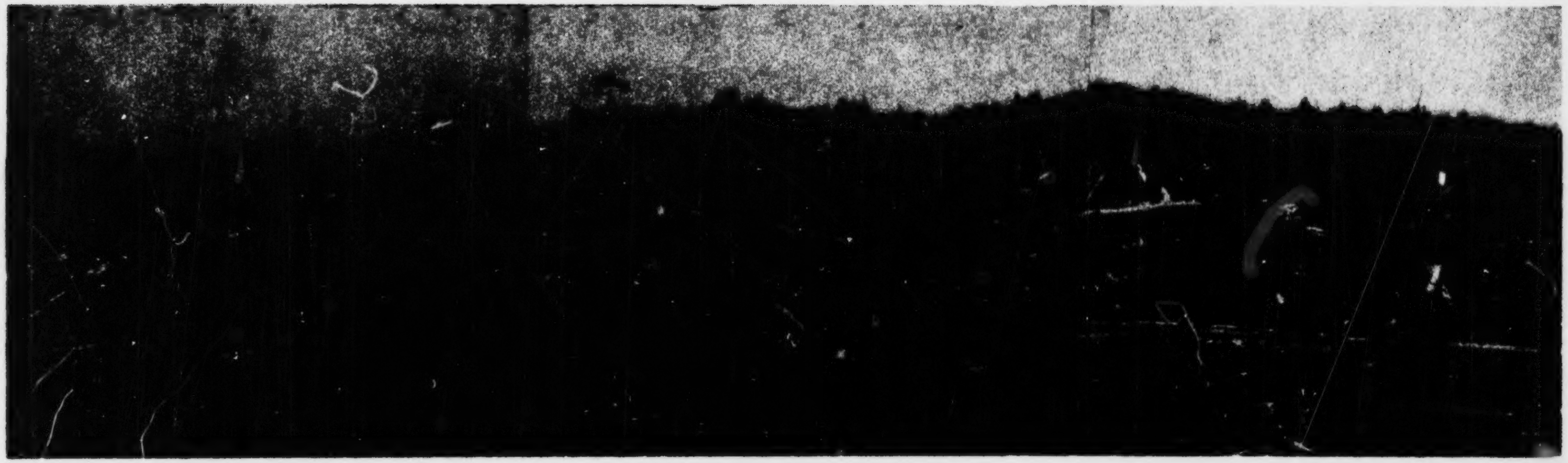


FIGURE 2-2 WASTE WOOD LEFT IN CLEARED AREAS

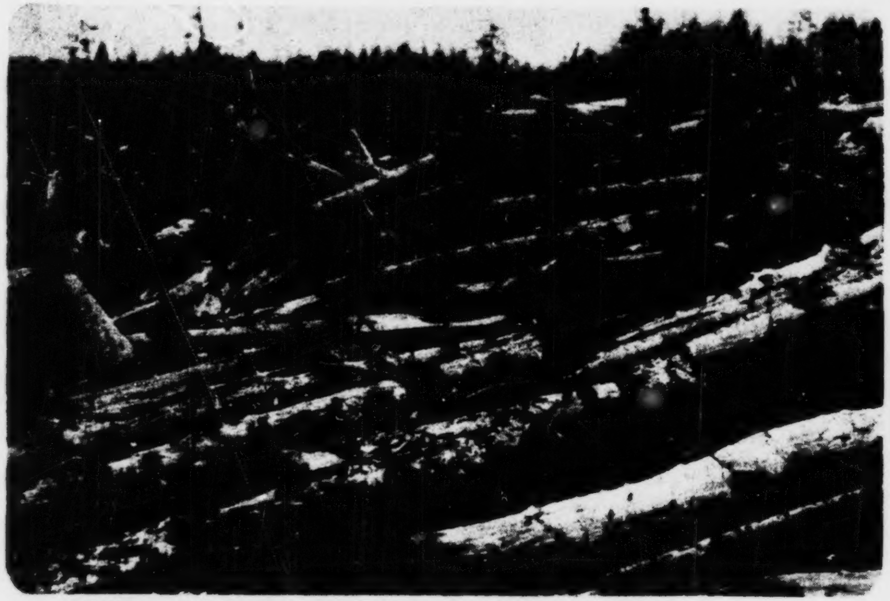


FIGURE 2-3 WASTE WOOD LEFT IN CLEARED AREAS

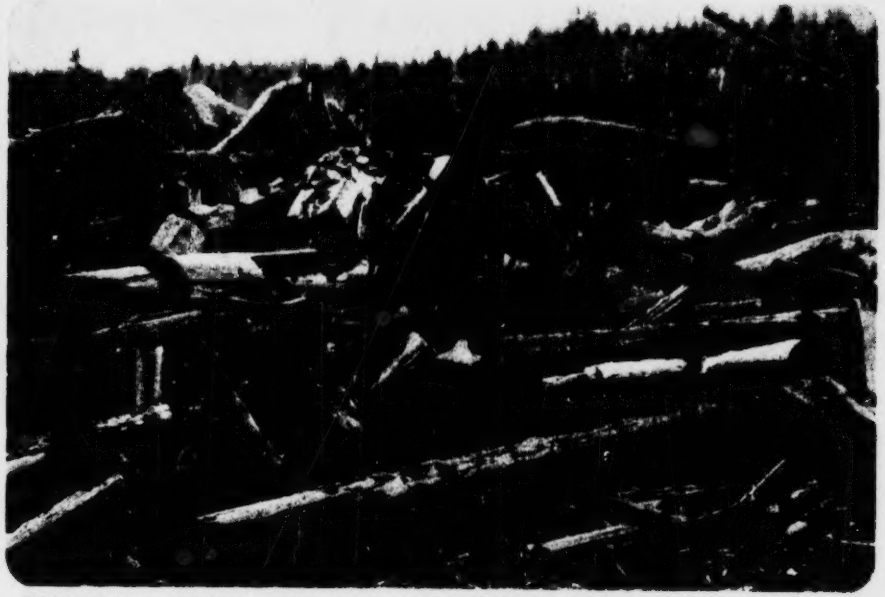


FIGURE 2-4 WASTE WOOD LEFT IN CLEARED AREAS

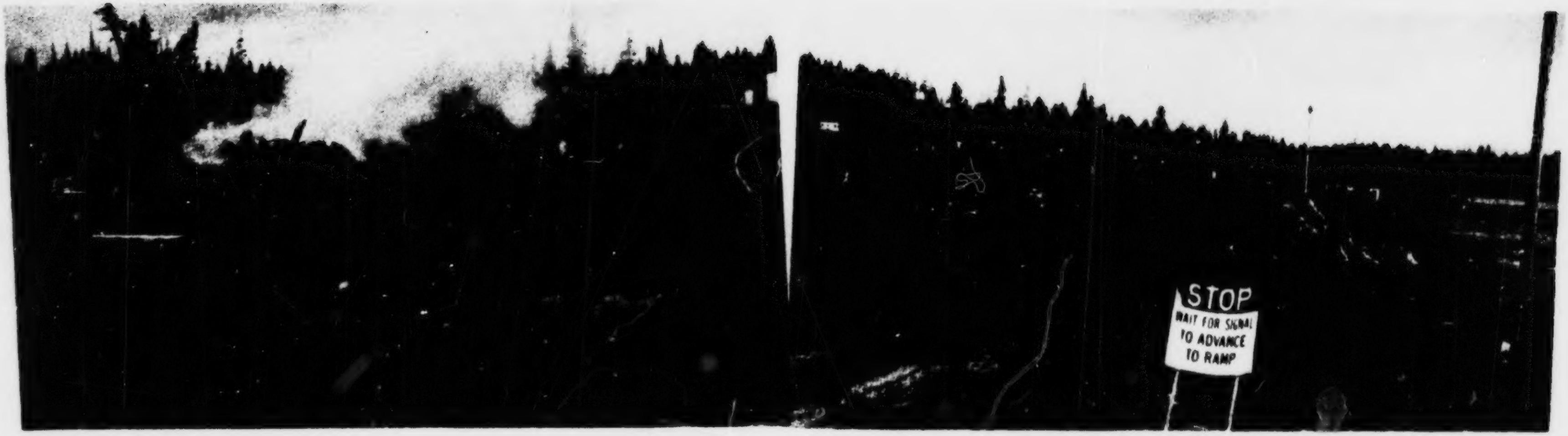


FIGURE 2 - 5 FERGUSON BAY LAND SORT

FIGURE 2-6 FERGUSON BAY LAND SORT 1

FIGURE 2-7 FERGUSON BAY LAND SORT 2

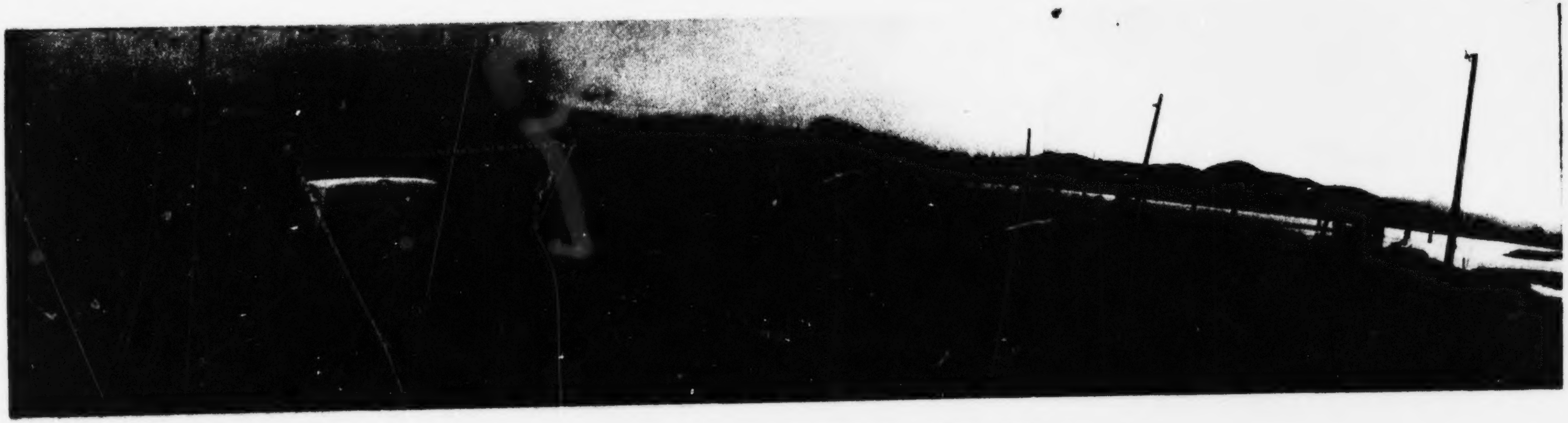


FIGURE 2-8 SKIDEGATE LAND SORT

FIGURE 2-9 SKIDEGATE WASTE WOOD DUMPED WITH MUNICIPAL SOLID WASTE 1

FIGURE 2-10 SKIDEGATE WASTE WOOD DUMPED WITH MUNICIPAL SOLID WASTE 2.

Under the current depressed market logging standard it is required that the logged areas be clear cut and that all merchantable timber be removed. It is also required that hemlock pulp logs be yarded to the landings so that they can be recovered at a later date when pulp markets improve. The cedar and cypress pulp logs and other wood waste can be left where it has fallen in the bush.

In addition to the wood waste produced in current logging operations, much of the wood waste from past operations could be economically salvaged if required as a feedstock for any system installed to operate on wood waste.

The wood waste generated in land sorts is disposed of in one of three ways. It is either buried in land fills mixed with municipal solid waste (Figs. 2-9 and 2-10) or buried in selected areas in layers approximately 1 m thick with alternate layers of soil and rock fill (Figs. 2-11 and 2-12). The disposition of this wood waste from land sorts is such that it would be impractical to ever attempt to redeem it as a feedstock for any wood waste fuelled system. More recently the wood residues and larger pieces are being burned at the Ferguson Bay land sort (Fig. 2-5).

In order to get a more detailed assessment of the wood waste availability in the Ferguson Bay area and to determine the cost of a wood waste fuel supply for a thermal generating station, a study contract was issued to the Forest Engineering Research Institute of Canada (FERIC).[15] FERIC has recently completed several studies regarding recovery and processing of forest residues in the southwest portion of Vancouver Island.

FIGURE 2-11 FERGUSON BAY WASTE WOOD DUMP

FIGURE 2-12

FERGUSON BAY WASTE WOOD DUMP

2.2 SOURCES OF WOOD WASTE FUEL

(a) Ferguson Bay Land Sort Debris

When logs are processed through a sorting operation on land, approximately 5 percent of the solid wood volume results in loose wood debris. With an adjacent thermal plant, this debris is an obvious source of fuel for the plant. The loose wood debris has an average bulk density of 400 kg/m^3.

The estimated long-term volume of debris generated at the Ferguson Bay sorting operation is:

$$425\ 000\ \text{m}^3/\text{a} \times 0.05 = 21\ 250\ \text{m}^3/\text{a}$$

$$21\ 250\ \text{m}^3/\text{a} \times 400\ \text{kg/m}^3 = 8500\text{t/a}.$$

Assuming the moisture content of the debris averages 55 percent (wet basis),

$$8500\ \text{t/a} \times 0.45 = 3825\text{t/a (dry basis)}.$$

If sortyard debris is used as a source of wood fuel for the thermal plant then it will contribute about 20 000 kJ/kg (gross heating value, dry basis). With this gross calorific value, a moisture content of 55 percent (wet basis) and an ash content of 5 percent (dry basis), the net calorific value of the wood fuel will be about 7100 kJ/kg of debris (wet basis).

The Skidegate sorting operation was not considered because of high ash content of the debris and the distance from Ferguson Bay.

Given the debris generation rates at the Ferguson Bay sortyard, the additional wood required from the Juskatla and Skidegate operations for the thermal plant will be:

50 000t/a - 3825t/a = 46 175t/a (dry basis).

(b) Log Sources at Justkatla and Skidegate Operations

In addition to sortyard debris, fuel for the plant can be sourced from logging debris left at the roadside, from low grade material that is normally uneconomical to log, or from low grade pulp logs. The pulp logs could be sorted and the poorer grade material could be diverted at the Ferguson Bay sortyard to the thermal plant rather than being shipped to Vancouver. The logging debris would require introduction of additional equipment to recover and transport it to the thermal plant. Uneconomic low grade wood waste could be recovered by the existing logging equipment but additional costs would be incurred.

(i) Pulp Logs

The volume of logs processed at the Skidegate and Juskatla operations are:

Total Annual Allowable Cut	665 000 m^3
Pulp Log Production	
- Skidegate Operations	36 000 m^3
- Juskatla Operations	63 750 m^3
Total	99 750 m^3

There is not an adequate volume of wood available in the pulp grades from Skidegate and Juskatla operations to supply the nominal thermal plant requirements of 50 000 ODt/a (120 470 m^3/a) alone.

(ii) Roadside Logging Debris

No detailed assessment was made of the amount of wood that is available as roadside logging debris. This material normally accumulates along the roadside or in the landings and is the result of:

- the yarding crew sending in logs that do not meet the utilization specifications;
- logs that are too short to load on the trucks;
- portions of logs bucked in the landing; and
- log breakage during yarding.

Although a detailed assessment of this material was not made, a visual examination was made of several logged areas at the Juskatla Operation. The amounts of material remaining after logging are similar to those encountered in other coastal areas where FERIC has done more detailed studies. In these areas, 5 to 10 percent of the material yarded to roadside may be logging debris. Much of this is not economically recoverable. An estimate of the wood waste that can be recovered with readily available equipment and conventional recovery systems is:

Juskatla and Skidegate Operations Annual Allowable Cut	665 000 m^3
Estimated Percentage as Logging Debris	5
Estimated Volume of Material	33 250 m^3

This volume alone is also less than that required by the thermal plant. If it is to be the next basic source of fibre after sortyard debris then it will have to be supplemented by pulp logs or the uneconomic, low grade wood waste.

(iii) Low Grade, Uneconomic Wood Waste

If the thermal plant created a demand for it then the low grade, uneconomic wood waste could be recovered and transported to the plant during active logging. The conventional cable logging systems would most likely be used to move the material from the logging setting to the landing. Harvesting costs would increase because of the reduced net log size. A second pass wood waste recovery system could be used using lighter equipment to reduce the recovery costs but this option has not been considered at this time.

Again, because of budget restrictions a detailed survey was not made to determine the volume of potentially useable low grade wood waste in the settings. However, from discussions with logging personnel and a brief field inspection this volume is estimated to be 5 to 10 percent of the total volume. This converts to:

Juskatla and Skidegate Annual Allowable Cut	665 000 m^3
Estimated Percentage as Uneconomic Material	7.5%
Estimated Volume of Material	50 000 m^3

(c) Summary of Potential Wood Fuel Sources

A summary of the potential sources of wood fuel for the Ferguson Bay thermal plant is:

Source	Volume (t) (dry basis)	Volume (m³)
Ferguson Bay Sortyard	3 825	N/A
Pulp Logs - Skidegate	13 800	36 000
- Juskatla	24 450	63 750
Roadside Logging Debris	12 750	33 250
Low Grade, Uneconomic Wood	19 200	50 000
Total	74 025	183 000

2.3 WOOD WASTE FUEL COSTS

There are two aspects to the cost or price of the wood. The first is the price at which MacMillan Bloedel is willing to sell the wood. The second is the wood cost the thermal plant can afford to pay and still remain economically viable. If the price and cost are reasonably close, then a contract could be negotiated. There is also a less tangible social worth benefit to British Columbia in utilizing a wood waste resource to produce electricity for remote community uses. The wood waste use will also result in a much cleaner country-side after the logging operation is completed.

The following analysis is an attempt to establish what the likely costs of recovering the various forms of wood will be. It is done in order to indicate a range of fuel costs the thermal plant is likely to encounter in order that a decision can be made whether or not the economics of the plant are attractive enough to warrant a more detailed assessment of a wood-fired thermal generating station. These estimates should be a starting point, not an ending point, in any negotiations between MacMillan Bloedel and B.C. Hydro.

(a) Sortyard Debris

With the pipe burner system used at Ferguson Bay for debris disposal the costs of disposal are usually \$0.10/m³ of logs sorted. Landfill disposal using a site within 5 km of the yard normally costs \$0.10 to \$0.15/m³ of logs sorted for loading, hauling and disposal site maintenance. The thermal plant could be thought of as a disposal site for the debris and most likely no additional operating costs would be incurred transporting the material the short distance from the yard to the plant. However, an initial cost will be required to extend the paved perimeter of the yard in the truck unloading area and to build a washing station for removing sand and grit from the incoming loads of logs. A rough estimate of this cost would be \$75,000. If this cost is spread over a 5 year period, then the annual cost would be \$15,000 or \$3.90/t (dry) of debris. With repair, maintenance and operating costs this most likely would become a continuing annual cost and is treated as such in this analysis.

(b) Log Costs

Wood acquisition costs will vary with the type of wood waste collected and the method used to recover and deliver it to the thermal plant. The following is an estimate of costs under several scenarios:

(i) Low Grade Pulp Logs Sorted and Diverted to Thermal Plant

Under this scenario the pulp logs would be harvested and transported using the normal production equipment, except at the sortyard the low grade logs would be sorted and diverted to the adjacent thermal plant rather than being shipped to the pulp mills.

Over the last 5 years the pulp logs have sold for between $18 and $24/m³. If towing costs ($12/m³) from Ferguson Bay to Vancouver are deducted then these logs have a value of $6 to $12/m³ at the land sort. As mentioned earlier, when log production flows to the Skidegate sorting operation the pulp logs would have to be woods sorted and backhauled to Ferguson Bay. This would add about $5.00/m³ in costs to the pulp logs from the Skidegate Operation. A summary of the pulp log acquisition costs is:

	Acquisition Cost	
	$/m³	$/t (dry)
Juskatla Pulp Logs	$ 6 - $12	$15.65 - $31.30
Skidegate Pulp Logs	$11 - $17	$28.70 - $44.35

For the purpose of this study the acquisition costs are averaged as:

	$/m³	$/t (dry)
Juskatla Pulp Logs	$ 9	$23.50
Skidegate Pulp Logs	$14	$36.50

(ii) Recovery of Roadside Logging Debris

One system that could be used to recover roadside logging debris places containers in the active logging landings. The containers are loaded with the wood waste that normally would be left in the landing. The cost estimate for this system is:

Assuming a 30 km one-way haul, one container can recover 20 m³ of debris per landing per day. One tractor truck unit can make four trips per day. On an annual basis 33 250 m³ of roadside debris is generated.

$$\frac{33\ 250\ \text{m}^3}{200\ \text{operating days/a}} = 165\ \text{m}^3/\text{day}$$

$$\frac{165\ \text{m}^3/\text{day}}{20\ \text{m}^3/\text{container}} = 8.3\ \text{containers/day}$$

With delays and other lost time, three tractor units and nine containers will be needed to recover an average of 165 m^3/day.

It is assumed that the charge out rate would be \$125/h for one tractor and three containers.

3 x \$125/hour x 8 hours/day = \$3000/day

\$3000/165 m^3 = \$18.20/m^3

The Ministry of Forests will require stumpage payments which can be assumed to be about \$1.00/m^3.

Total Cost = \$19.20/m^3

= \$50.10/t (dry)

Another system for wood waste recovery uses choker skidders and self-loading logging trucks to recover residual pieces from the roadside and landings after active logging has been completed. Relative to the container system the main advantages of this system are that it does not interfere with active logging and the recovery standard can be varied. The main disadvantage is that the costs are higher than the container system. However, some companies prefer this system because of the lack of interference with primary production. The cost of a system for Juskatla and Skidegate operations is estimated as:

Assuming a 30 km one-way haul, a skidder plus operator and chokerman can recover 60 m³ per day. On an annual basis 33 250 m³ of wood is recovered.

$$\frac{33\ 250\ \text{m}^3}{200\ \text{operating days/a}} = 165\ \text{m}^3\text{/day}$$

$$\frac{165\ \text{m}^3\text{/day}}{60\ \text{m}^3} = 2.8\ \text{systems}$$

With delays and other lost time, three skidders and three self-loading logging trucks will be needed to recover 165 m³/day.

Cost of system:

Logging truck - 3 x 8 hours/day x $70/hour	=	$1680
Skidders - 3 x 8 hours/day x $60/hour	=	1440
Chokerman - 3 x 8 hours/day x $20/hour	=	480
Chainsaws - 3 x $25/day	=	75
Stumpage - $1/m³ x 165 m³	=	165
Total		$3840

$$\frac{\$3840}{165\ \text{m}^3} = \$23.30/\text{m}^3 = \$60.80/\text{t (dry)}$$

(iii) Low Grade, Uneconomic Wood Waste

The cost per cubic metre of falling, yarding, loading and sorting operations in the logging operation are heavily influenced by the log size. The selling price per cubic metre is affected by the log grade or quality which is determined by the amount of log defect and size. Consequently, the smaller, lower grade logs have higher harvesting costs and lower selling prices.

If the thermal plant was to use low grade, uneconomic wood waste as a source of fuel then overall logging costs would increase when this material was yarded, loaded and sorted. The amount of the increase would depend mainly on the decrease in log size. The following is an estimate of the increase on cost:

- Present logging conditions

	$/m³	$/Log
Fixed Costs	$13	$20.80
Variable Costs	$25	$40.00
	$38	$60.80

Piece Average = 1.6 m³/log

$$\frac{665\ 000\ \text{m}^3}{1.6\ \text{m}^3/\text{log}} = 415\ 625\ \text{logs}$$

If this material was recovered the log size would probably average 0.50 m³/log. This would reduce the overall average to the following:

$$\frac{665\ 000\ \text{m}^3}{1.6\ \text{m}^3/\text{log}} = 415\ 625\ \text{logs}$$

$$\frac{50\ 000\ \text{m}^3}{0.50\ \text{m}^3/\text{log}} = 100\ 000\ \text{logs}$$

$$\frac{715\ 000\ \text{m}^3}{515\ 625\ \text{logs}} = 1.39\ \text{m}^3/\text{log}$$

The marginal cost of recovering this material is estimated as:

Marginal Costs = $40/log x 100 000 logs

= $4,000,000

$$\frac{\$4,000,000}{50\ 000\ m^3} = \$80/m^3$$

$$= \$210/\text{dry tonne}$$

The analyses assumes that fixed costs remain constant when in effect they probably are a step type function that varies with volume. Thus, the marginal costs are probably understated somewhat. However several smaller logs could be handled at a time countering some of the increased costs.

(c) Cost on the Chip Pile

The cost of the wood fuel on the chip pile will vary mainly with the method or combinations of methods used to recover the raw wood fibre. It is assumed that all methods or combinations would use the sortyard debris as a source of material. In these types of studies, it is also usually assumed that the least costly sources of logs will be used first. However, because of pulp mill demand MacMillan Bloedel may not be able to commit all of the pulp logs to the thermal plant. Thus as shown in Table 2-1, three scenarios are given: one in which pulp logs are used first, one in which roadside logging debris is used first then pulp logs, and one in which roadside logging debris and low grade, uneconomic wood waste is used first and then pulp logs.

2.4 SUMMARY OF SUPPLY

In summary it was determined that a mixture of sortyard debris, logging waste, roadside residue and pulp grade logs from the Juskatla Division of MacMillan Bloedel is sufficient to supply the proposed Ferguson Bay thermal generating station nominal wood fuel requirements of 50 000 t/a (bone dry). However, if a thermal plant is to be built, then close planning and coordination will be required between MacMillan Bloedel and

TABLE 2-1
SUMMARY OF WOOD FUEL SUPPLY COSTS

A. SCENARIO I

Source	Method	Volume (m³)	Volume (Dry Tonnes)	Unit Cost ($/Dry Tonne)	Total Cost ($/a)
Sortyard Debris	N/A	N/A	3 825	$3.90	$14,920
Pulp Logs	Conventional				
	Juskatla	63 750	24 450	$23.50	$574,575
	Skidegate	36 000	13 800	$36.50	$503,700
Logging Waste	Containers	20 675	7 925	$50.10	$397,050
Total		120 425	50 000	$29.80	$1,490,245

B. SCENARIO II

Source	Method	Volume (m³)	Volume (Dry Tonnes)	Unit Cost ($/Dry Tonne)	Total Cost ($/a)
Sortyard Debris	N/A	N/A	3 825	$3.90	$14,920
Logging Waste	Containers	33 250	12 750	$50.10	$638,775
Pulp Logs	Conventional				
	Juskatla	63 750	24 450	$23.50	$574,575
	Skidegate	23 415	8 975	$36.50	$327,590
Subtotal		120 415	50 000	$31.10	$1,555,860

C. SCENARIO III

Source	Method	Volume (m³)	Volume (Dry Tonnes)	Unit Cost ($/Dry Tonne)	Total Cost ($/a)
Sortyard Debris	N/A	N/A	3 825	$3.90	$14,920
Logging Waste	Containers	33 250	12 750	$50.10	$638,775
Low Grade	Conventional	50 000	19 200	$210.00	$4,032,000
Pulp Logs	Conventional				
	Juskatla	37 100	14 225	$23.50	$334,300
Subtotal		120 350	50 000	$100.40	$5,020,000

B.C. Hydro to assure that a sufficient amount of wood fuel is available to meet the thermal station requirements at a reasonable cost.

The cost of the raw wood fuel delivered to the thermal plant will ultimately depend on the mixture of the wood supply. The mixture would be determined by MacMillan Bloedel and B.C. Hydro. However, under the three scenarios examined in this study the cost was found to vary from $29.80 to $100.40/t (dry basis).

Preliminary discussions with the Valuation Branch of the B.C. Forest Service[12] has indicated that some form of stumpage rate would apply to low quality timber which would be used for operation of a wood-fuelled thermal generating station on the Queen Charlotte Islands. Land sort debris could be available at $3.90/ODt with no stumpage charges added, but this would only be a small portion of the total station requirements. The forest residues, cull logs and possibly some of the poorer grade pulp wood could be available at a nominal stumpage rate as low as $0.10/m^3 under an Order-in-Council provided under Section 84(5) of the Forest Act. The Order-in-Council is issued on a yearly basis and would have to be renewed annually.

A longer term arrangement could be made for X and Y grade pulp logs which would probably qualify for a one-quarter minimum stumpage rate under B.C. Regulation 560/78. For reference, current one-quarter minimum stumpage rates by species on the Queen Charlotte Islands are:

Balsam	$0.52/m^3	Douglas Fir	$0.76/m^3
Cedar	$1.13/m^3	Hemlock	$0.49/m^3
Cypress	$1.06/m^3	Spruce	$1.18/m^3

These rates are subject to change on a monthly basis.

The species mix at Juskatla and Skidegate logging operations is approximately 50 percent hemlock, 30 percent cedar, 17 percent spruce and 3 percent cypress resulting in an average stumpage rate in the order of \$0.82/m³ (\$2.13ODt). This agrees fairly closely with the \$1/m³ used in the previous cost scenarios.

For the purpose of this study, it can be assumed that sufficient wood waste could be available from the MacMillan Bloedel Juskatla Division logging operations to fuel a 10 MW thermal generating station located at Ferguson Bay. The unprocessed wood waste fuel cost delivered to the thermal station can be expected to cost between \$29.80 and \$100.40 per oven-dried tonne, including stumpage. Scenario III has been used in this study to represent the wood fuel supply mixture with a resulting raw wood fuel cost of \$100.40/ODt. For the benefit of future wood fuel supply costs discussions the break even cost of fuel has been calculated in Section 7.0.

2.5 PEAT

Wood waste has been used as the biomass resource in the previous discussions of biomass utilization in the Queen Charlotte Islands. However, another viable indigenous biomass resource available on the Islands is peat.

Peat is dead and partly decayed plant material, that has accumulated in a wet environment, where stagnant waters inhibit the circulation of oxygen vital to decomposing organisms. Peat is widespread over the Queen Charlotte lowland where muskeg is a dominant feature of the landscape (Fig. 2-13). The muskeg contains fibric peat derived principally from sphagnum moss, to a depth of approximately 0.5 m and humified sedimentary peat derived from sedges, roots and leaves to an average depth of approximately 2 m.

Peat is classified using a humification scale established by Von Post;[13] the characteristics of each peat are described in Table 2-2. Better fuel peats are above H5,[13] but peat classified as low as H3 may be used

DIXON
ENTRANCE
MASSET

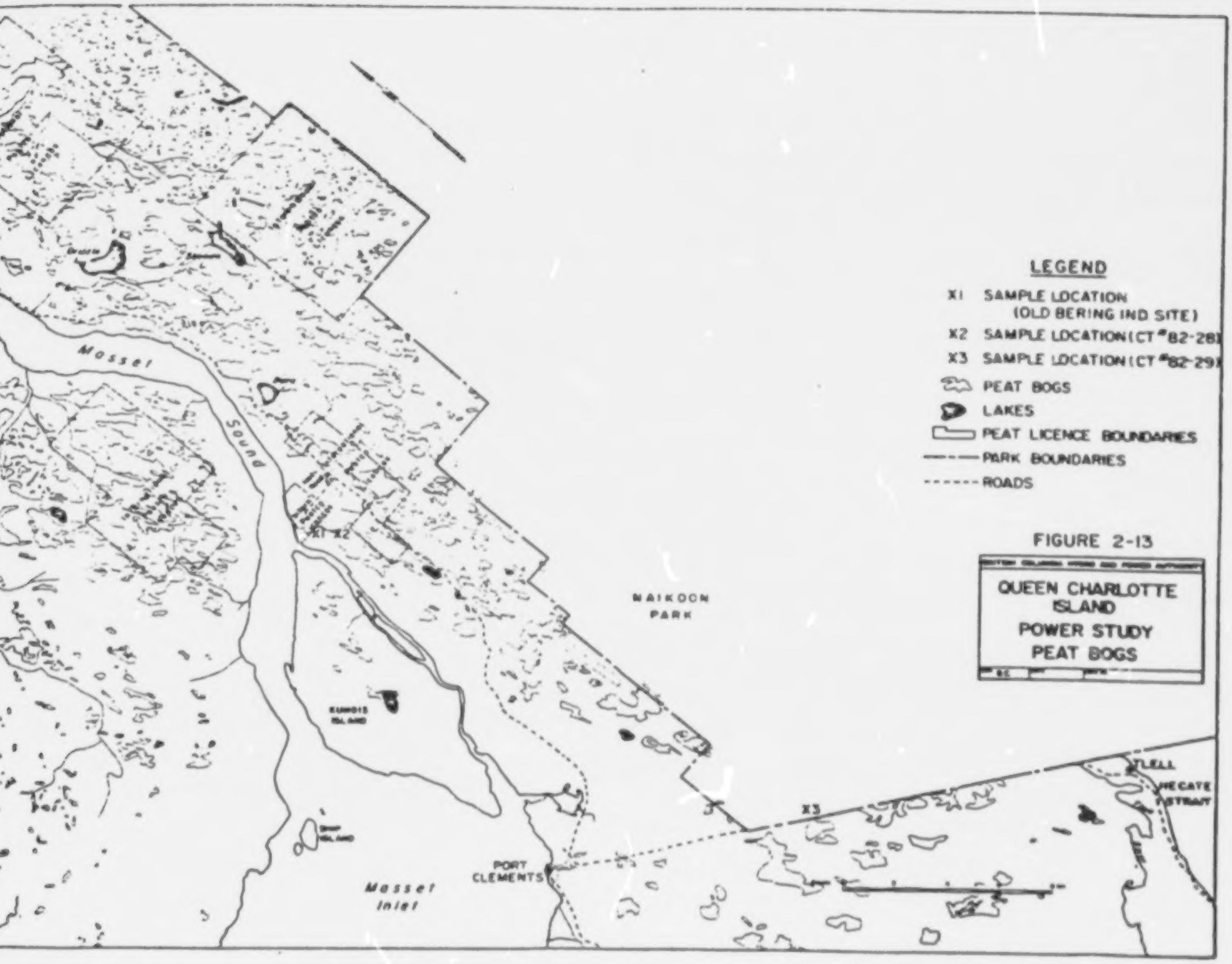


FIGURE 2-13

QUEEN CHARLOTTE ISLAND
POWER STUDY
PEAT BOGS

TABLE 2-2

SWEDISH GEOLOGICAL SURVEY
METHOD FOR DETERMINATION OF HUMIFICATION OF RAW PEAT SAMPLES[13]
(FROM VON POST 1926)

				Upon Squeezing Through Fingers		
Humification Scale	Evidence of Degree of Decomposition	Plant Structure	Mud Present	Water Passing	Amount of Peat Substance Passing	Residue
1	Nil	-	Nil	Yes Clear and colourless	-	-
2	Almost nil	-	Nil	Yes Clear and yellow brown	-	-
3	Very little	-	Little	Yes Distinctly turbid, very turbid	-	Not pulpy
4	Little	-	Some	Very turbid	-	Somewhat pulpy
5	Fairly evident	Barely recognizable	Moderate	Moderate amount	Some	Very pulpy
6	Fairly evident	Indistinct less in residue	-	-	One-third	Very pulpy, shows plant structure more than unsqueezed turf
7	Strong	Fairly recognizable	Much	Yes Gruelly and dark in colour	One-half	-
8	Strong	Very indistinct	Much	Yes or no, if it does, gruelly	Two-thirds	Consists of more resistant roots, fibres, etc. in main
9	Almost fully decomposed	Almost unrecognizable	Very much	-	Almost all, as a uniform paste	-
10	Completely decomposed	Entirely without plant structure	Entirely muddy	No free water	All	-

in a thermal plant. The peat on Graham Island ranges from H1 to H10, depending on depth; deeper peat has a higher Von Post index number.

Several characteristics are important in determining the potential for peat utilization including density, mineral matter content, moisture content and thickness.[14] The in-situ bulk density of peat is dependent on its degree of decomposition and its mineral matter content. The bulk density can range from 48 to 320 kg/m³. Fibric peat, such as the surface peat on Graham Island, usually contains less than 2 percent mineral matter which should result in a lower density. The surface peat is only slightly decomposed which would indicate a moderate density. The deeper sedimentary peat contains as much as 66 percent ash on a dry basis. These high ash peats have a high density and a low heating value. The water content, when saturated, ranges from 95 percent for less decomposed peats to 75 percent for those that are more decomposed. If the peat is less decomposed it drains more easily. Most peats are acidic and have a pH ranging from 3 to 6. The peat should be more than 1.8 m thick and have a domed structure for satisfactory harvesting. Unfortunately the Queen Charlotte Island peat bogs have a concave surface structure and high water making draining and harvesting difficult.[21]

The results from analysis of a peat sample taken from the Old Bering Industries site (Fig. 2-14) on Graham Island, at the end of Nadu Road, are listed in Table 2-3. Sample X_1 consisted of red brown, fibric peat from a pile which lies above the water table (Fig. 2-15). There was no mud and little evidence of decomposition. The sample was H2 to H3 on the humification scale. Samples X_2 and X_3 are drilled samples taken by Dr. Charles Tarnocai.[21] The potential fuel peat in the area is estimated at 0.67 to 3.0 m thick. The best sample (Sample X_3) in Table 2-3 was taken by Dr. Charles Tarnocai from a site in Naikoon Park north of the Port Clements-Tlell highway shown on Fig. 2-13.

Fig. 2-14 View of Peat Bog at Bering Industries Site

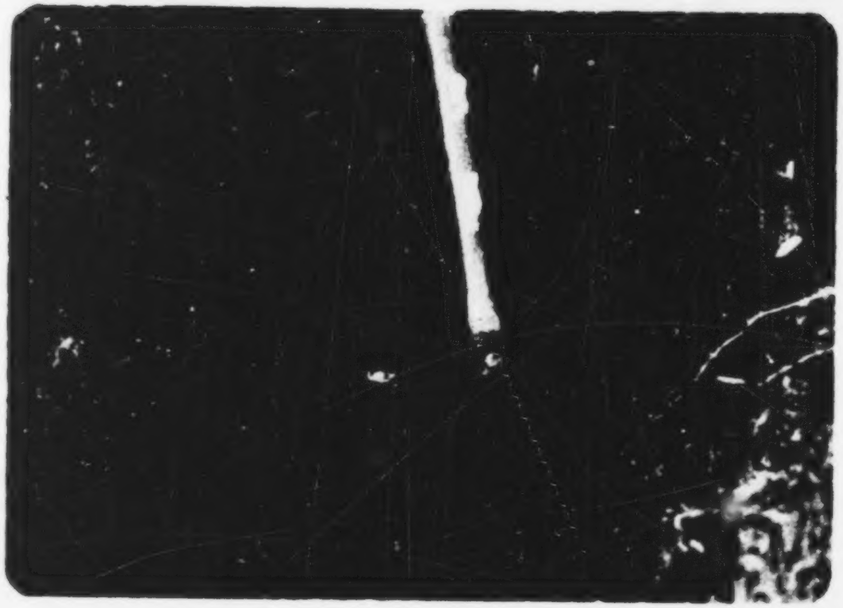


Fig. 2-15 Peat Sampled at Bering Industries Site

TABLE 2-3

ANALYSIS OF QUEEN CHARLOTTE ISLANDS PEAT

Sample Location x_1: (Old Bering Industries Site)

No. 2 Q.C. Peat	As Received Basis	Air Dry Basis	Dry Basis
Residual Moisture	-	9.51	-
Total Moisture	88.6	-	-
Heating Value: (kJ/kg)	2 314	18 364	20 294
(Btu/lb)	995	7 895	8 725

Sample Location x_2:[21] (Charles Tarnocai Sample No. 82-28

Sample Number	Depth (cm)	Von Post Rating	Sphagnum Moss (%)	Sedge (%)	Amorphous Peat (%)	Sedimentary Peat (%)	Other (%)	Ash (%)	Oven-dried Calorific Value calories/gram
1	0-24	H2	99				1	2	5268
	24-41	H4	40	10	40		10	5	5394
	41-50	H8		10	80		10	45	3537
2	0-29	H2	99				1	2	5525
	29-99	H3	99				1	2	5495
	99-117	H8		20	60		20	63	6185
	117-137	H10				98	2	66	3258
4	0-24	H2	98				2	8	4908
	24-59	H3	98				2	4	5588
	59-74			10	70		20	10	5484
	74-87	H10				99	1	65	2886

Sample Location x_3:[21] Charles Tarnocai Sample No. 82-29

Sample Number	Depth (cm)	Von Post Rating	Sphagnum Moss (%)	Sedge (%)	Amorphous Peat (%)	Sedimentary Peat (%)	Other (%)	Ash (%)	Oven-dried Calorific Value calories/gram
2	0-65	H8		20	70		10	15	5508
	65-125	H5		50	30		20	26	4799
	125-190	H7		20	70		10	50	4208
3	0-20		99						
	20-32			10	80		10		
	32-41		Mineral Layer						
	41-65			30	60		10		
	65-105			3	95		2		
	105-207			30	60		10		
4	0-22				100			3	5322
	22-56	H8		20	70		10	3	5549
	56-146	H5		50	20		30	6	6336
	146-153	H9				98	2	6	6518
	153-200	H7		30	55		15	3	6124
	200-298	H8		40	45		15	11	5460

A weight-moisture curve was derived by Montreal Engineering in a report prepared for Energy, Mines and Resources Canada (Fig. 2-16).[13] The in situ density of peat from the Queen Charlotte Islands was taken as 540 lb/yd^3 (320 kg/m^3) on the basis of that curve. Similarly, a Btu-moisture curve was derived in the same report (Fig. 2-17).[13] The analyses for Queen Charlotte Islands' peat are also illustrated in the figure.

The main problems with peat utilization are its high moisture content (greater than 90 percent in its natural state), its correspondingly high weight relative to heating value, its bulk, its occurrence in thin layers and the small bog sizes. Also the bogs on the Queen Charlotte Islands are difficult to drain. The advantages of peat are its widespread occurrence on Graham Island and its easy accessibility since it is at the surface; in addition it is on land that is currently of little use. Peat is also low in sulphur.

Drying of peat is accomplished by draining, mechanical dewatering or solar drying. Western Peat Moss Ltd. of Delta dewater to an average of 78 percent moisture whereas International Peatco Ltd. of Chilliwack markets a press which dewaters to approximately 70 percent moisture. Further drying to 50 percent moisture or less requires thermal drying. In British Columbia, where both rainfall and labour costs are high, solar drying is impractical.

As a biomass fuel resource on the Queen Charlotte Islands, peat generally has a varying humification level and high ash making it a relatively poor fuel. Also dewatering and drying of peat would be expensive operations and solar drying is impractical. A recent sample of peat taken north of the Port Clements-Tlell highway in Naikoon Park appears to have fairly good fuel peat qualities and ranges up to 2.88 m in depth. However the sample was taken from within the Naikoon Park boundary and may not be available as a fuel. Consequently, although

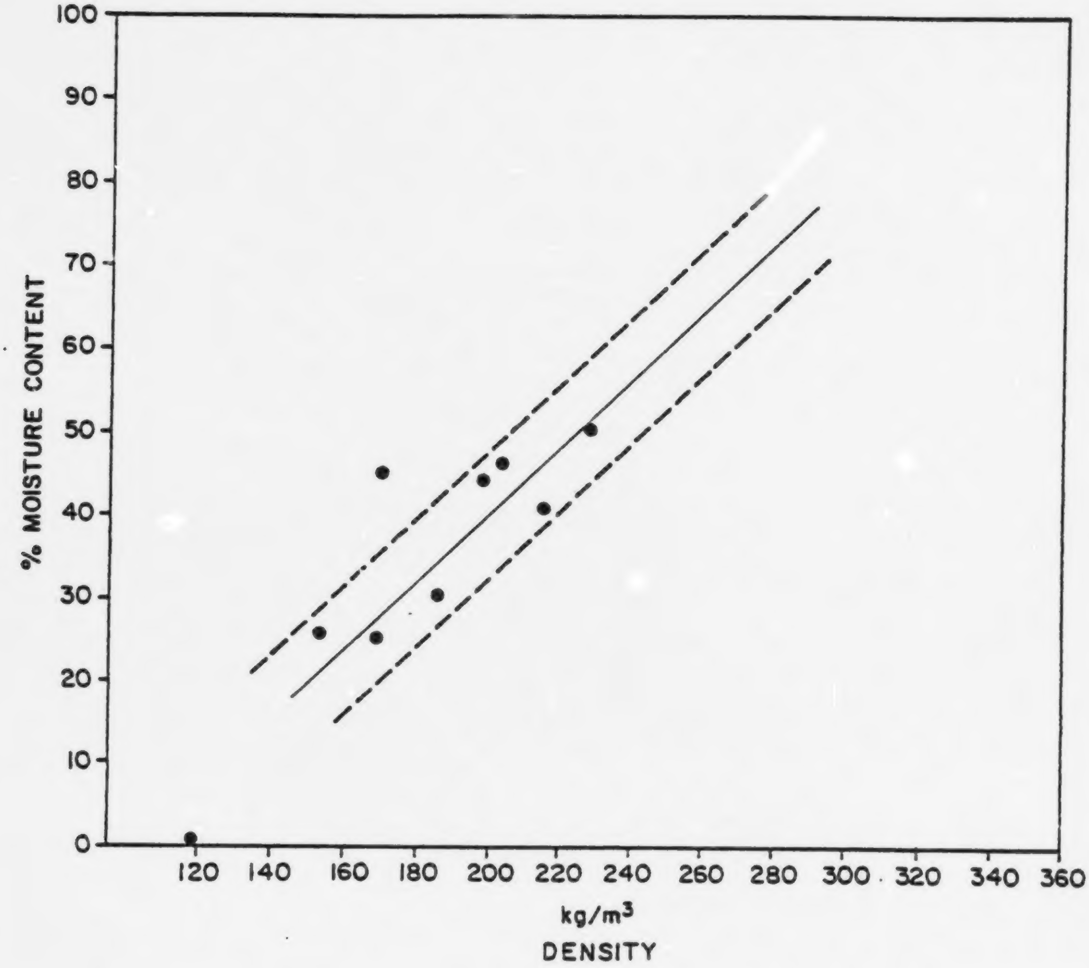


FIGURE 2-16

DENSITY/MOISTURE CONTENT OF FUEL PEAT

NOTE: THE POINTS REPRESENT THE CHARACTERISTICS
OF A NUMBER OF CANADIAN PEATS

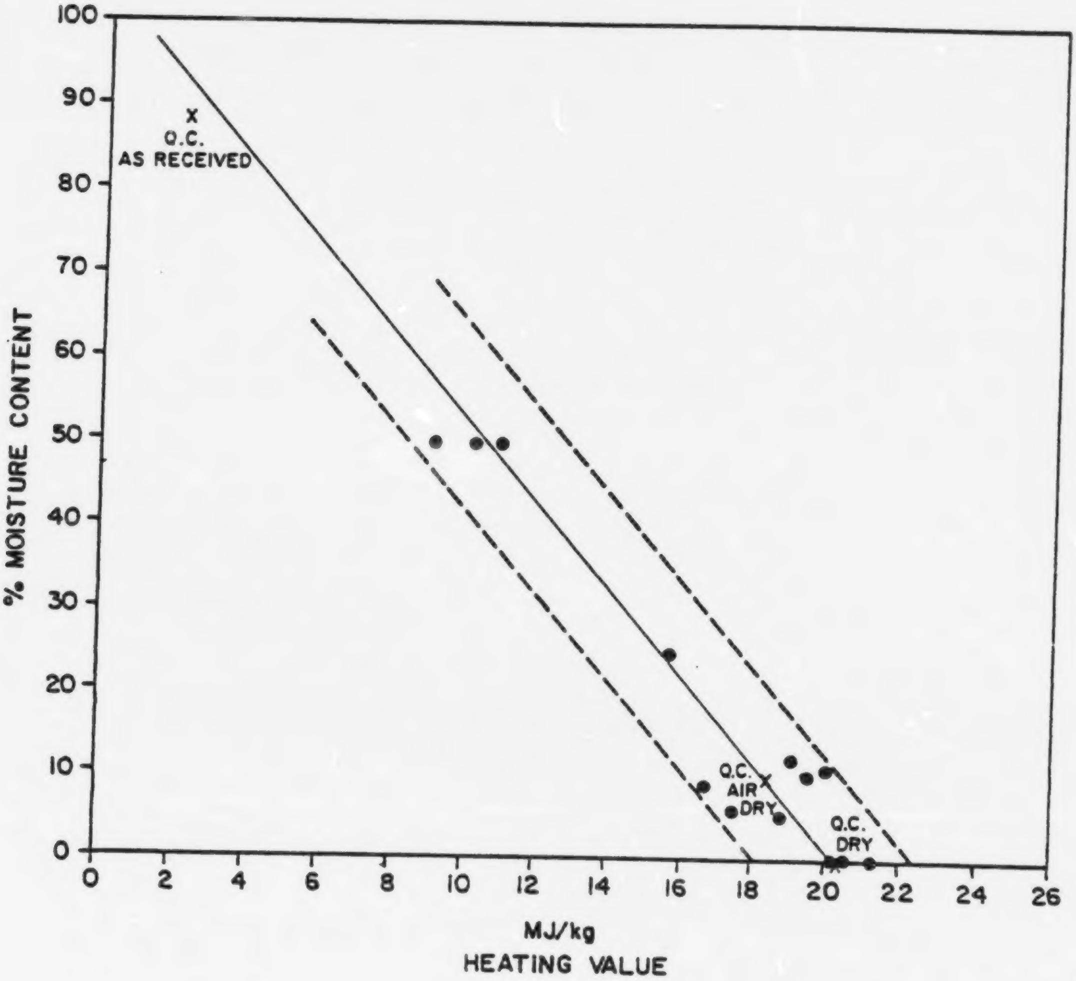


FIGURE 2-17

HEATING VALUE/MOISTURE CONTENT OF FUEL PEAT

NOTE: THE POINTS REPRESENT THE CHARACTERISTICS OF A NUMBER OF CANADIAN PEATS peat is an alternative biomass fuel it is only presented here for reference.

SECTION 3.0 - SITE EVALUATION

3.1 LOCATION AND OPERATIONAL LOGISTICS

The proposed wood-fired thermal plant site is to be located at Echinus Point on the west end of Ferguson Bay in Masset Inlet (Fig. 3-1). A total area of approximately 3 ha will be required for the 10 MW thermal generating station.

A number of factors influence the selection of a site for a thermal generating station and the Ferguson Bay site was chosen for the following reasons.

1. Ferguson Bay is central to the existing electrical load and to the predicted future load. The load centres of Masset and Queen Charlotte City/Sandspit are approximately equidistant from Ferguson Bay and therefore transmission costs would be minimized.

2. The proposed site is relatively flat and could be easily cleared.

3. The site is adjacent to the MacMillan Bloedel Ferguson Bay land sort property. This land sort, which is the largest in the Queen Charlotte Islands, would produce the most waste wood. Also, logging residues and pulp logs recovered from the logging operation could be handled and sorted through the land sort.

4. The site is adjacent to deep tidewater which could be used for once-through condenser cooling. In addition, wood waste for fuel could be barged to the site from other locations around Masset Inlet, e.g. the Dinan Bay and McClinton Bay land sorts.

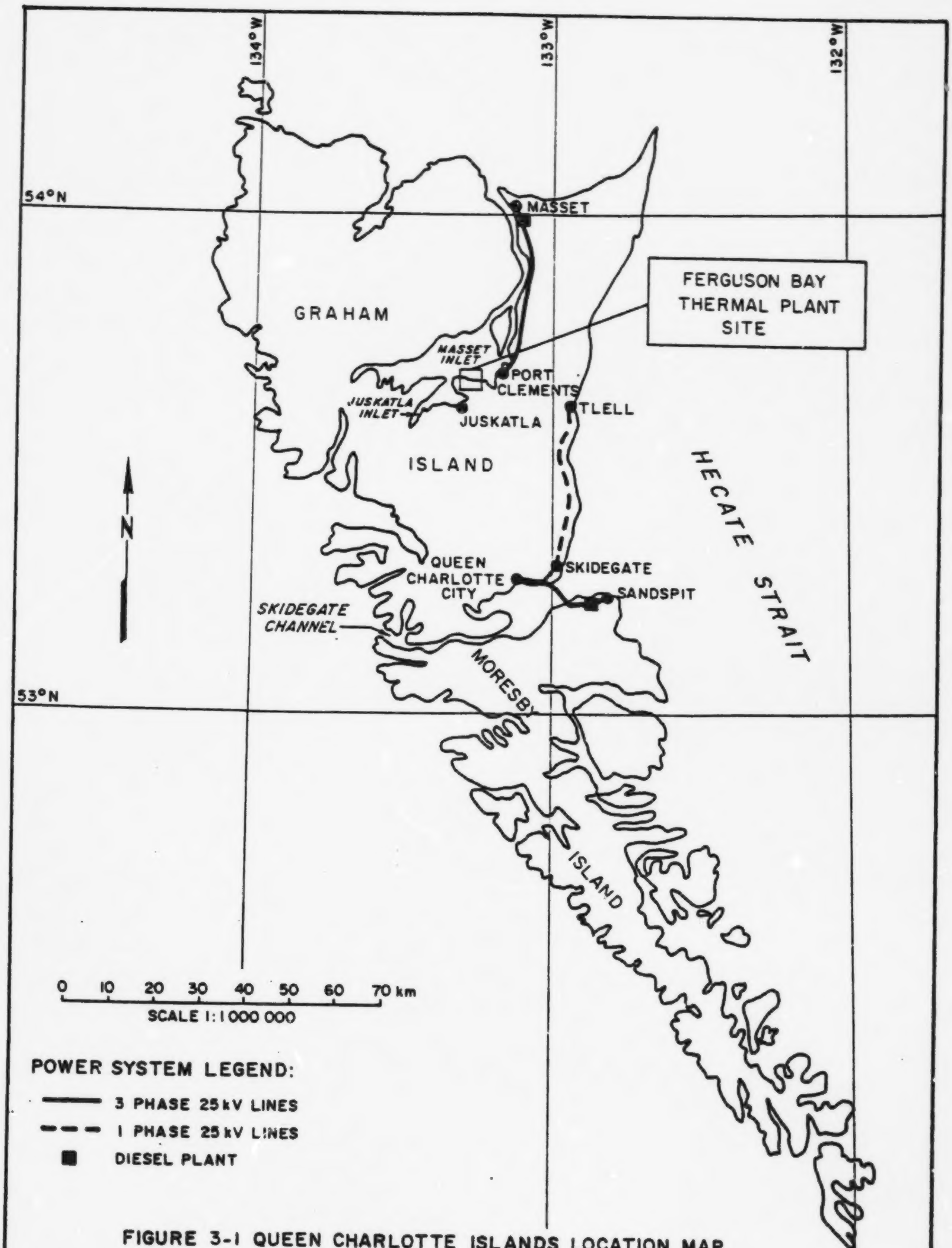


FIGURE 3-1 QUEEN CHARLOTTE ISLANDS LOCATION MAP

5. At least part of the existing road system owned by MacMillan Bloedel could be utilized for plant access.

6. There is a nearby supply of gravel which may be suitable for concrete. A rock quarry in the area could supply rock for fill.

7. The village of Port Clements could be expanded to provide living facilities for plant operating and maintenance personnel.

3.2 SITE CONDITIONS

The site is presently overgrown with second growth timber consisting primarily of spruce and cedar as shown in Fig. 3-2. There is little underbrush and the forest floor is covered with deadfalls and rotting vegetation. It was estimated that approximately a 2 m layer would have to be removed to expose the underlying rock.

The site geology is sedimentary rock consisting of marine stony clays, till, outwash sands and gravel. The area lies to the east of the Sandspit fault which extends from Juskatla through Cumshewa Head and under Hecate Strait. The fault trends N30°W to N40°W and dips 60°NE to 80°NE. The fault is currently active and the eastern block has dropped more than 1000 m relative to the western block. Lateral movement is also believed to be substantial.

The plant site is relatively flat and slopes gently upward from a wide beach covered with cobble-sized rock (5 cm to 25 cm). The foreshore shelves steeply to water depths of 10 fathoms and the marine charts indicate a sand bottom in the area.

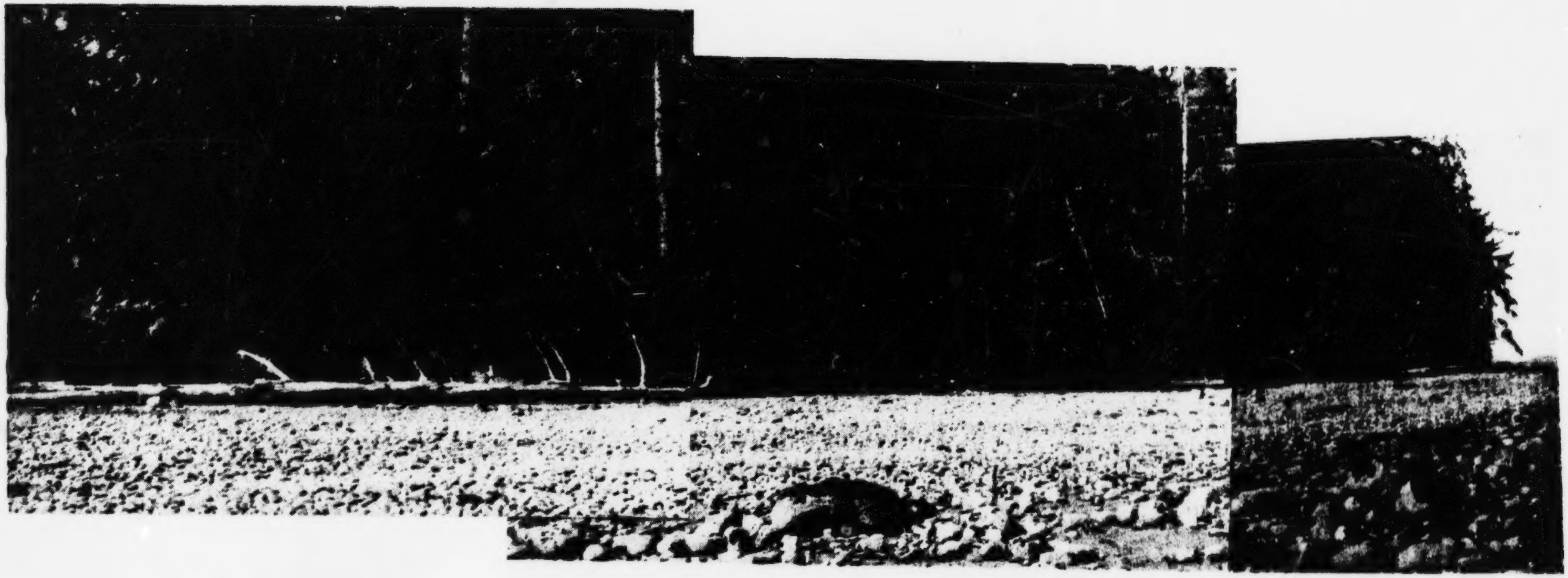


FIGURE 3-2 ECHINUS POINT THERMAL PLANT SITE VIEWED FROM MASSET INLET

3.3 SITE SERVICES

The site is located approximately 27 km by road from the village of Port Clements and can be reached over a network of well maintained gravel roads. This road system is owned by MacMillan Bloedel and maintained by them. The first 14 km from Port Clements is classified as an industrial main road and is open to public traffic 24 hours a day. The remaining 13 km is an active logging road which is the main haul route to the Ferguson Bay land sort. As such there is restricted access to the area via this road. However there are several secondary haul road routes to the general vicinity and it is anticipated that arrangements could be made with MacMillan Bloedel to use one of these alternate routes as the plant access road.

Since the plant site is in a remote location there are no existing services except the access road. Prior to the beginning of construction it would be necessary to arrange for a supply of electric power, compressed air, potable domestic water and sanitary services.

An adequate supply of fresh water poses the greatest problem and will require further investigation. It is anticipated that a satisfactory supply, both for domestic use and boiler feed water, can be obtained from wells on the plant site. Alternatively, it should be possible to pipe in a supply from the Yakoun or Mamin rivers or from Florence Creek. This option would be more expensive, requiring a pumping complex and lengthy pipeline and would have additional environmental impacts which would have to be investigated.

SECTION 4.0 - WOOD-FIRED THERMAL GENERATING STATION

4.1 TERMS OF REFERENCE

The B.C. Hydro Station Projects Division was requested to prepare a conceptual design and cost estimate for a 10 MW (nominal) wood-fired thermal generating station to meet the Queen Charlotte Islands electricity requirements.

For this study a conventional small biomass-fired thermal generating station concept has been developed. The new 10 MW centralized generating station has been designed to supply the near-term forecast load, exclusive of new industrial demand, for the Queen Charlotte Islands. The existing diesel generating stations will be connected to the plant with new transmission lines and the diesel stations will be maintained for peaking or standby. Included in the design are wood residue collection and fuel processing facilities designed to meet the requirements of the station. Basic plant design parameters, layout and offsite facilities have been developed within B.C. Hydro, with some detailed design specifications provided by outside consultants.

4.2 STATUS REVIEW

A complete review of the options available for generating electricity from wood residues has been recently carried out by B.H. Levelton and Associates Ltd. for ENFOR (Canada).[1] Table 4-1 summarizes the characteristics of the systems that were analyzed.[1] At that time (December 1982) it was determined that, of all the systems studied only those using steam-driven turbines or engines can be considered as proven commercial technology. The combination of a wood gasifier with an internal combustion engine can be considered as near commercial technology. There are numerous suppliers of these systems, most presently developing or demonstrating systems of 100 to 700 kW capacity. Common problems with gasifier/engine systems are poor automatic feeding of wood fuel, tar deposition in the engine, inadequate means of tar disposal and poor voltage/frequency control.

At present no gas turbines are commercially available for operation with wood-derived fuel gas. Problems exist with firing this gas in a turbine because of its low heating value and the presence of particulate matters and tars. Kongsberg has done some development work in defining the turbine modifications needed to accept a fuel such as wood-derived fuel gas. Gas turbines appear suitable only for systems of capacities near the upper part of the capacity range for diesel engines, roughly capacities greater than 3 MW.

For this study, the only wood-fired generating systems being considered are the conventional steam boiler-steam turbine combination and the gasifier internal combustion engine combination which are at or are near a commercial stage of development. Several systems have very good future potential, such as the gasifier-gas turbine, combustor-gas turbine, combustor-Stirling engine and pulverizer-solid fuel turbine systems, but are not commercially available at this time.

Producing steam for power generation using a wood-derived fuel gas can be considered as commercial technology. This system avoids gas cleanup and problems with evolved wood tars, but must satisfy boiler regulations and generally is suitable only when there is a need for process steam. Unless there is a need for fuel gas, or a gas-fired boiler is already in place, a combustor/boiler combination is recommended over a gasifier/boiler combination.

TABLE 4-1

PERFORMANCE CHARACTERISTICS AND SELECTION GUIDELINES FOR GENERATING SYSTEMS

Primary Conversion/ Primer Mover	Characteristics	Advantages	Disadvantages	Equipment Needing Improvement	Suitable Forest Industry
STEAM BOILER:					
-Steam Turbine		-proven equipment with many options -good operating flexibility -worker familiarity -moderate cost -packaged units available	-requires trained operators -need water source -need use for steam -high maintenance	-none	-pulp and paper mills -sawmills with dry kilns -plywood and veneer mills
System Status	-commercial				
Power Output (kW)	->300, >1500 typical				
Boiler Code	-applicable				
-Steam Engine		-lower steam rates than turbines below 2 MW -good for variable speed and slow speed applications -good torque characteristics -low maintenance -worker familiarity -good operating flexibility like turbines	-limited availability, sizes and options -requires trained operators -need water source -need use for steam	steam engine	-pulp and paper mills -sawmills with dry kilns -plywood and veneer mills
System Status	-commercial				
Power Output (kW)	-25 - 3000; up to 20 000 possible				
Boiler Code	-applicable				
GASIFIER AND PYROLYZER:					
-Fuel Cell		-no moving parts in fuel cell -low emissions -operating flexibility -modular construction -high efficiency, over-wide load range	-unproven -no commercial systems available -very sophisticated unfamiliar technology -high cost	-gasifier -gas reformer -fuel cell	-unknown
System Status	-conceptual (pilot operating on naptha)				
Power Output (kW)	->20				
Boiler Code	-not applicable				

TABLE 4-1 (Continued)

Primary Conversion/ Primer Mover	Characteristics	Advantages	Disadvantages	Equipment Needing Improvement	Suitable Forest Industry
-**Gas Turbine**		-suitable for automation -compact -low labour requirement	-best for base load applications -poor part-load performance -operational inflexibility -fouling of turbine -unproven, limited availability -high maintenance	-gas cleanup -turbine combustor -control system	-possibly sawmills -specialty product mills
System Status	-conceptual/ research				
Power Output (kW)	-500 - >100 000				
Boiler Code	-not applicable				
-**Internal Combustion Engine**		-suitable for automation -low labour requirement -moderate maintenance -fair equipment availability	-possible problem with engine control due to fluctuations of gas quality -tar and particulate deposits in engine -scrubber water disposal -lube oil contamination	-gas cleanup -control system	-sawmills -specialty product mills
System Status	-demonstration/ commercial				
Power Output (kW)	-100 - >2000				
Boiler Code	-not applicable				
-**Steam Turbine**		-tars incinerated maximizing energy recovery from fuel gas -gas available for other uses -others as per steam boiler	-limited equipment availability -more complex than combustor/boiler combination -ohters as per steam boiler	-gas burner -steam engine	-pulp and paper mills -sawmills with dry kilns -plywood and veneer mills
System Status	-demonstration/ commercial				
Power Output (kW)	-300 - 8000				
Boiler Code	-applicable				
-**Steam Engine**					
System Status	-demonstration commercial				
Power Output (kW)	-25 - 3000				
Boiler Code	-applicable				

TABLE 4-1 (Continued)

Primary Conversion/ Primer Mover	Characteristics	Advantages	Disadvantages	Equipment Needing Improvement	Suitable Forest Industry
COMBUSTOR:					
-Gas Turbine					
System Status Power Output (kW)	-pilot ->500	-clean gas for turbine -suitable for automation -if closed cycle, good part load performance and efficiency -low to moderate turbine maintenance	-need use for hot gas or steam -thermal inertia poses control problem -best for base load, steady operation -limited availability of heat exchanger for high temperature	-heat exchanger -control system	-pulp and paper mills
Boiler Code	-not applicable; with combined cycle is applicable				
-Stirling Engine					
System Status	-prototype/ demonstration	-engine uses isolated working fluid -long engine life -suitable for automation	-ash fouling of heater in stirling engine -thermal inertia poses control problem -worker infamiliarity -limited availability of engine -small output	-gas cleanup -Stirling engine	-sawmills -specialty product mills
Power Output (kW)	-<40, presently				
Boiler Code	-not applicable				
-Steam Turbine					
System Status Power Output (kW)	-commercial -300 - 11 000				
Boiler Code	-applicable	-hot gases available for other uses -flexible modular system structure -others as per steam boiler	-thermal inertia poses control problem -others as per steam boiler	-steam engine	-pulp and paper mills -sawmills -plywood and veneer mills
-Steam Engine					
System Status	-demonstration/ commercial				
Power Output (kW)	-25 - 3000				
Boiler Code	-applicable				

TABLE 4-1 (Continued)

Primary Conversion/ Primer Mover	Characteristics	Advantages	Disadvantages	Equipment Needing Improvement	Suitable Forest Industry
COMBUSTOR:					
-**Thermionics**					
System Status Power Output (kW)	-research -4 - >100 000	-no moving parts in converter -good for combined cycle	-unproven -no commercial systems available -high cost -unfamiliar technology -need use for hot gases	-all system components	-unknown, E/T poor at present for all mills
Boiler Code	-not applicable				
PRESSURIZED COMBUSTOR:					
-**Gas Turbine**					
System Status Power Output (kW)	-research -1000 tested	-suitable for automation -compact	-thermal inertia of combustor poses control problem -best for base load -ash fouling and wear of turbine -no commercial systems available	-gas cleanup -gas turbine -fuel feed system	-sawmills -speciality product mills
Boiler Code	-not applicable				
PULVERIZER:					
-**Solid Fuel Turbine**					
System Status Power Output (kW)	-conceptual -unknown	-simple system -suitable for automation	-high power required for pulverizing -ash fouling and wear of turbine -no commercial systems available	-all system components	-sawmills -speciality product mills
Boiler Code	-not applicable				
LIQUEFACTION:					
-**Gas Turbine, Internal Combustion Engine**					
System Status Power Output (kW)	-conceptual -N/A	-conventional prime movers	-unproven -very low conversion efficiency -high cost	-all system components	-unknown
Boiler Code	-not applicable				
HEAT RECOVERY BOILER:					
-**Organic Vapor Turbine**					
System Status Power Output (kW)	-demonstration -0.1 - 1000	-recovery of waste heat -higher efficiency than steam below 400°C -best for recovery at 100°C - 300°C	-toxic fluids -problem to handle and dispose of fluids -limited availability of systems -degradation of fluids -worker unfamiliarity	-all system components	-pulp and paper mills
Boiler Code	-probably does apply				
-**Steam Turbine**					
System Status	-commercial				
-**Steam Engine**		-SEE STEAM BOILER			
System Status	-commercial				

4.3 PLANT DESIGN AND OPERATION

The thermal generating station design has been based on the load growth projection given in Section 1.4 (i.e., to supply 45.54 GW·h of electricity per year at a peak load of 9.47 MW in 1994/95).

It was decided that for this study, a plant design would be developed incorporating two 5 MW (net) units in a single building. This would allow flexibility in the scheduling of power generation and maintenance activities while minimizing the need to use the diesel units. The total installed capacity of the plant would be 10.4 MW (2 x 5.2 MW). The plant auxiliary power requirements (i.e. plant equipment, lighting, heating, etc.) would be 0.4 MW leaving 10.0 MW available for distribution. The overall plant heat rate would be 21 600 GJ/GW·h. Table 4-2 provides some basic plant design data.

Costs for this base case plant were developed from information received from outside consultants and manufacturers as well as from internal B.C. Hydro sources. Alternative designs with a single 10 MW (net) unit, and five 2 MW (net) units were also costed using information from outside sources and adapting certain costs from the base case station design.

The wood waste fuel quality has been taken as outlined in Section 2.2.[15]

Whole logs	-	20 000 kJ/kg (oven dry basis) 11 290 kJ/kg (wet basis), moisture 35 percent
Sortyard debris	-	20 000 kJ/kg (oven dry basis) 7 100 kJ/kg (wet basis), moisture 55 percent

The moisture of the wood fuel is an important parameter. Steam boilers can handle wood fuels with moisture levels up to 55 percent (net basis). At levels above this the moisture in the fuel reduces the amount of heat

TABLE 4-2

10 MW (2 x 5 MW) WOOD-FIRED THERMAL GENERATING STATION BASIC PLANT DATA

Item	
Boiler Output (each)	7.0 kg/s
Total Boiler Output (2)	14.0 kg/s
Steam Pressure	4140 kPa (ga)
Steam Temperature	400°C
Plant Heat Rate (send-out basis)	21,600 GJ/GW·h
Heating Value Wood Fuel	11,290 kJ/kg
Fuel Size	50 mm x 50 mm
Fuel Feed Rate/Boiler	5.4 t/h
Generator Output (each)	5.2 MW
Voltage	12.5 kV/3 ph/60 Hz
Speed	1800 rpm
Exhaust Pressure	6.67 kPa (abs)
Water Flow/Condenser	0.25 m^3/s
Cooling Water Inlet Temperature	7°C
Cooling Water Outlet Temperature	21°C
Site Elevation	Sea Level

avaiable for the steam raising process. If the moisture exceeds 50 to 55 percent then covered storage and/or dryers would be required to control and reduce the moisture level. With the wood fuel given above for the study, there appears to be no concern. The volume of sortyard debris represents only 8 percent of the total volume of wood fuel required annually therefore the moisture level of 55 percent is of no concern as the fuels would be stored in log form until use (35 percent moisture). Minimum moisture pick-up is expected during preparation, handling and in the chip piles. However, the moisture level must be confirmed in further studies and the need for covered storage and dryers studied in more detail.

Plant operation was assumed to be 8760 hours per year with forced outages and annual overhaul of the plant being covered by operation of the existing diesel generation stations maintained on standby.

The design has taken into account environmental concerns such as stack emissions and water pollution. These areas appear to be of little significance but would need to be addressed in more detail as discussed in Section 6.0.

Log handling operations would be planned to allow delivery of wood according to the forest industry logging schedule i.e., 200 days per year on a one shift per day basis, with a stockpile of logs being maintained to ensure a fuel supply for the plant for the balance of the year.

Fuel preparation would be carried out for 250 days per year on a 2-shift per day, 5 days per week schedule with a stockpile of prepared fuel to be used for weekends and emergency use. Dry storage facilities may be needed for this fuel storage.

The thermal plant operations will be scheduled for 3 shifts per day, 365 days per year. Routine maintenance has been assumed to be carried out on day shift only, with major overhaul and extraordinary maintenance being carried out by outside labour sources probably on a contract basis.

4.4 SITE LAYOUT

As noted in Section 3.0, the site selected for the 10 MW plant is on Masset Inlet at Echinus Point, close to the MacMillan Bloedel logging activities adjacent to the land sortyard, and within easy reach of the Island's power grid.

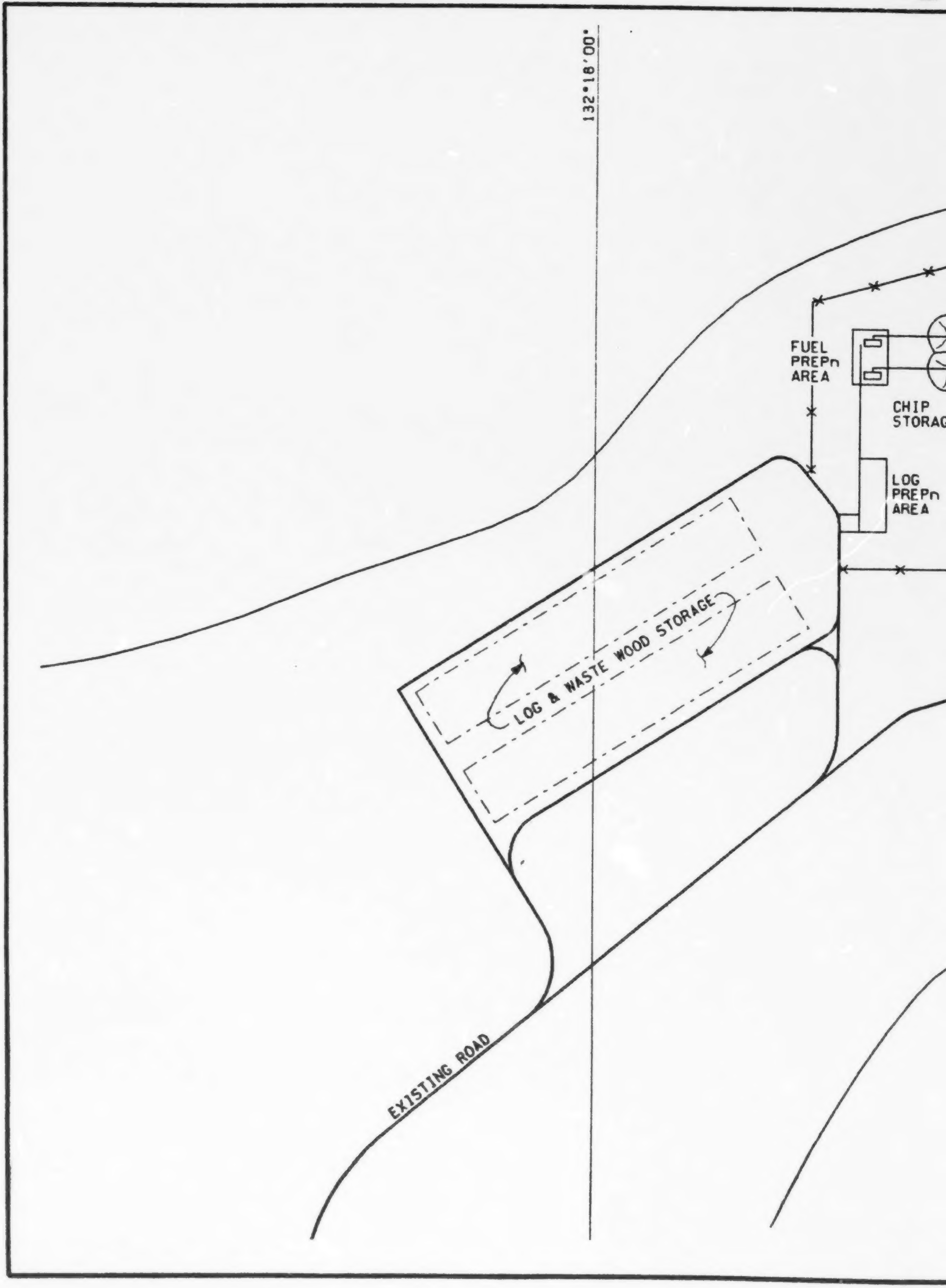
The entire plant including log storage area, fuel preparation facilities, chip storage, generating plant and associated facilities occupies approximately 3 ha. The proposed site layout is shown in Fig. 4-1.

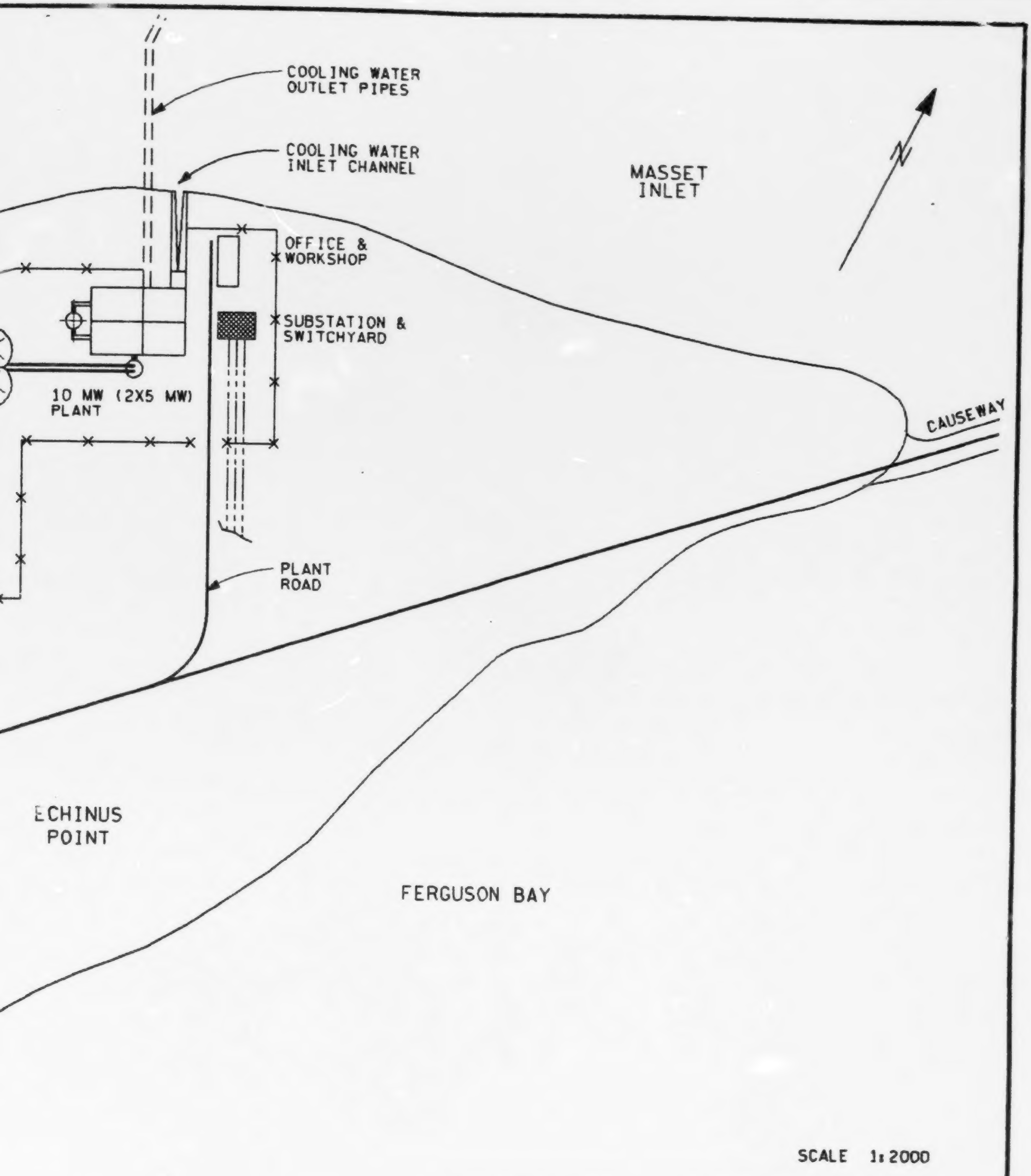
The site is relatively flat and would require clearing and grading down to bedrock. Backfill material required would be available from a local quarry.

An existing gravel road can be upgraded for construction purposes and normal plant access. Also, a breakwater located at the end of Echinus Point may be suitable for barge unloading during plant construction.

The log storage yard with an area of 1.5 ha, would be located at the western edge of the site to provide easy access for the logging trucks. The fuel preparation area would be located at the eastern edge of the log yard and includes the chip storage piles.

The generating station has been situated near the shore for access to cooling water and has been arranged to allow for expansion towards the south.


132°18'00"
FUEL PREPn AREA
CHIP STORAG
LOG PREPn AREA
LOG & WASTE WOOD STORAGE
EXISTING ROAD



QUEEN CHARLOTTE ISLANDS
10 MW WOOD FIRED
THERMAL GENERATING STATION
PROPOSED SITE LAYOUT.

FIG 4-1

The switchyard and workshops would be located to the east of the plant so as not to hinder plant expansion. The plant site area would be fenced and provided with the necessary drainage systems and lighting.

Temporary services such as water and power will be required for construction purposes. It has been assumed that potable water will be available on-site from wells. This water supply would also be used for the plant make-up feed water and other general services.

In-plant access roads will be provided between the respective areas and connected to the main access road through security gates.

4.5 WOOD FUEL PREPARATION

Wood fuel would be delivered under contract to the log storage and handling yard located adjacent to the thermal plant. From the FERIC report it is anticipated that 92 percent of the total raw fuel would be received in the form of whole logs up to 1 m in diameter directly from the logging area, and 8 percent in the form of debris from MacMillan Bloedel's dry land sortyard on Ferguson Bay.

It is estimated that about 49 000 t (oven dry weight) of wood fuel at the specified quality would be required annually to meet the projected load in 1994/95.

The wood fuel preparation operations would consist of two principal activities i.e., log storage and fuel preparation.

(a) Log Storage

Raw logs would be delivered to the site either directly to the fuel processing area to minimize handling, or to the storage area for stacking and/or sorting.

An estimated storage area of 1.5 ha would be required to stockpile up to a 3-month supply of logs to accommodate the difference between the thermal plant operating and log delivery schedules.

Equipment provided to handle the logs into and out of storage would include a 10 t log loader and a front-end loader.

All logs would pass through a water spray system to remove sand, stones and mud which are detrimental to the fuel preparation and thermal plant operations.

(b) Fuel Preparation

The fuel preparation operation would process the logs through a sorting deck using saws and hydraulic splitters to reduce them to a nominal size 0.5 m x 0.5 m x 1.50 m long to suit the hogging machines.

Wood chippers were considered along with hogs as the processing equipment. However, on advice from the outside consultants regarding chip size requirements and operating considerations, wood hogging machines were included in the fuel preparation equipment.

A conveyor transfers the split logs to one of two duplicate hogs for reduction to a nominal 50 mm x 50 mm chip size. Sortyard debris would be handled in a similar manner although future studies may indicate the need to screen this material depending upon the volume to be handled and contaminants such as rocks.

The chips would be conveyed to an outside storage pile of about 5 days capacity to provide fuel for weekend operations or emergency requirements. Reclaim from this pile would be by dozer into a reclaim conveyor for delivery to a day storage hopper adjacent to the plant. A hard packed or concrete pad may be required for the chip storage area to avoid pick-up of mud, gravel, etc. in the reclaim operations.

Future studies may consider covering the chip pile to prevent an increase in moisture content in the fuel due to rainfall.

4.6 THERMAL PLANT

(a) Introduction

The study considered two commercially available waste wood fired boiler systems:

1. Conventional stoker fired boiler - commonly used in the forest industry in B.C. for power and/or process steam production.

2. Fluidized bed boiler increasingly used in various industries for power and process steam production using a variety of fuels including refuse.

In fluidized bed combustion, fuel is injected and burned in a fluidized bed of mineral matter, such as sand or limestone. The bed of fuel and mineral matter is subjected to an evenly distributed flow of air and the materials become suspended in the gas stream. Eventually the bed becomes turbulent and mixing of particles occurs resulting in an efficient combustion process.

Fluidized bed boilers are suitable for high ash fuels, and are able to handle stones and tramp materials picked-up in the fuel. They can also handle a range of fuels in a given installation which offers some flexibility to the operation. They are also able to handle changing load conditions.

Emissions such as SO_2 and NO_x are controllable through the operating characteristics of fluidized bed combustion. The production of SO_2 can be controlled by the injection of limestone into the combustion chamber, and the low combustion temperature in the combustion process (850°C) minimizes the formation of NO_x.

However, the sulphur content of the proposed wood fuel is less than 0.1 percent, therefore, emissions of SO_2 are not expected to be a problem. NO_x emissions similarly are not expected to be of concern.

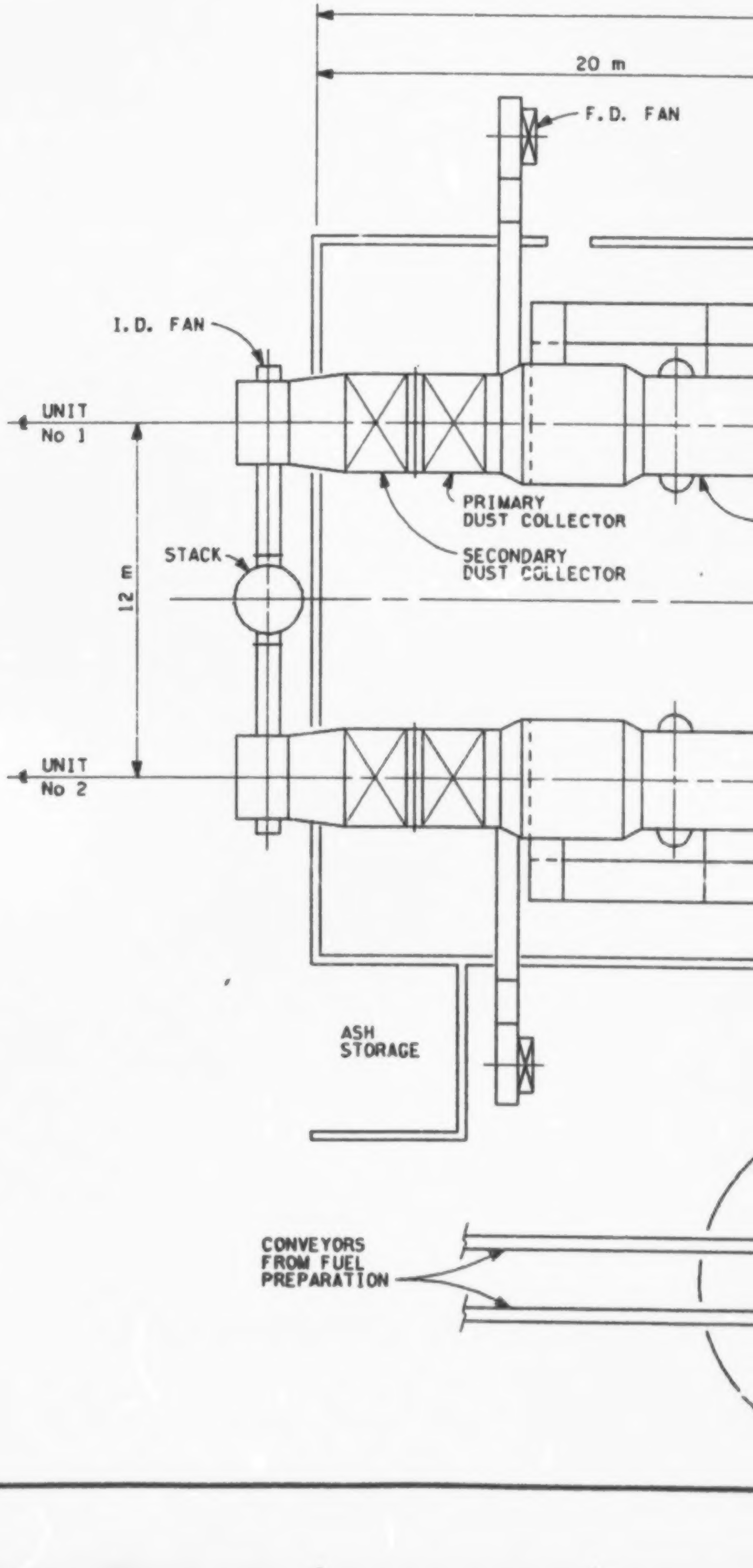
The advantages of the fluidized bed boiler over the conventional wood burning boiler are not of significant benefit in this study, given the low sulphur and ash contents of the wood fuel. Also, there appears to be sufficient wood fuel available to meet the plant requirements thus there is no need to consider burning alternate fuels.

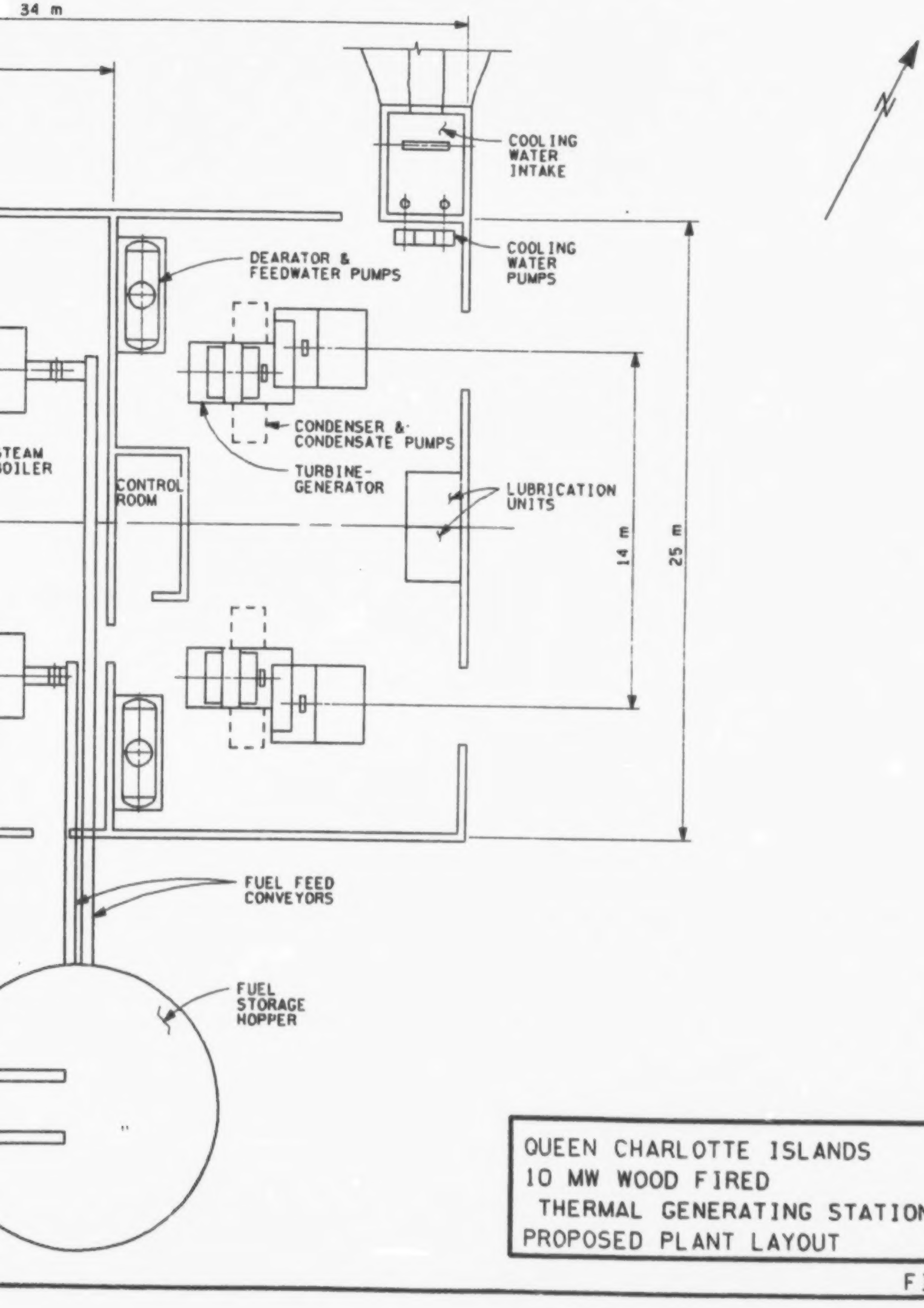
In developing the costs for alternative plant designs, it was noted that the capital costs for the fluidized bed boiler were significantly higher than for the conventional boiler. The operating costs also appear to be higher due, in part, to the higher auxiliary power requirements.

Therefore, for the purposes of this study the conventional boiler and plant was selected as the preferred alternative.

(b) Plant Layout

The plant building, about 850 m^2 in area as shown in Fig. 4-2, would house both 5 MW (net) generating units comprising boilers, turbine-generators and their necessary auxiliary equipment as well as a centrally located control room. The basic plant data for the station is provided in Table 4-2.


20 m
F.D. FAN
I.D. FAN
UNIT No 1
PRIMARY DUST COLLECTOR
SECONDARY DUST COLLECTOR
STACK
12 m
UNIT No 2
ASH STORAGE
CONVEYORS FROM FUEL PREPARATION



QUEEN CHARLOTTE ISLANDS
10 MW WOOD FIRED
THERMAL GENERATING STATION
PROPOSED PLANT LAYOUT

FIG 4-2

The boilers would be arranged to allow the use of a single flue gas stack.

Ash from the operation will be delivered to a disposal site outside of the plant area.

The various major plant components are described below:

1. Steam Boiler - Each 5 MW boiler would supply about 7.0 kg/s (55,000 lb/hr) of steam to the turbine at 4140 kPa and 400°C (600 psig and 750°F), consuming about 5.4 t/h (oven dry weight) at maximum continuous rating (M.C.R.). The equipment would be modular in design allowing maximum shop fabrication in order to minimize and simplify field erection. The water-tube boiler with a superheater section would be complete with a water-cooled vibrating grate for continuous ash removal.

   A pneumatic ash removal system would handle bottom ash from the boiler and fly ash from the flue gas cleaning system.

   Diesel fuel would be used as both a start-up and supplementary fuel.

2. Turbine Generator - Each single valve multi-stage turbine, would be rated to produce 5.2 MW at the generator terminals at the steam conditions of 4140 kPa (gage) 400°C and 6.67 kPa (absolute) exhaust pressure. A single extraction point provides steam to a deaerating feedwater heater. The generator would deliver 6000 kV·A of 12.5 kV, 3 PH, 60 Hz power at 1800 rpm.

   The turbine and generator would be connected through a gear reducer and the entire assembly would be mounted on a steel underframe complete with all necessary lubrication, cooling, protection and control equipment.

Mounted with the turbine will be a saltwater-cooled condenser.

3. Cooling Water System - The once through cooling water system would deliver 0.25 m^3/s (3300 IGPM) of seawater to each condenser. The inlet water temperature has been taken as 7°C and the temperature at discharge 21°C.

   The system would comprise duplicate pumps taking water from a sump located within the plant. Water would flow to the sump through a channel excavated from Masset Inlet to the sump. A trash screen and travelling water screen would be included in the system.

   Further information will be required on water temperature and flow patterns, tidal variations and water depth in the area before design details can be formulated.

4. Feedwater System - The feedwater system for each boiler would include a deaerating feedwater heater, duplicate feedwater pumps, duplicate condensate extraction pumps, and all the necessary valves and fittings.

   Since some form of water treatment will be required, a small water treatment plant has been included in the cost estimate. Further studies to confirm the availability and to determine the quality of the make-up water from local wells would be necessary prior to the selection of a specific plant.

5. Flue Gas Cleaning - The proposed flue gas cleaning equipment would include primary and secondary multi-cyclone dust collectors. This equipment would be designed to reduce the

particulates in the flue gas to the required Pollution Control Board (PCB) 'A' emissions level of 5.5 mg/mol.

The sulphur content of the wood fuel is expected to be less than 0.1 percent therefore emissions of SO_2 are expected to be well within any PCB guidelines. Similarly emission of NO_x are not expected to be a problem.

Further studies may be necessary to confirm this in the detailed design stage.

6. Ash Disposal - The total quantity of ash resulting from the operation of two units would amount to about 6 t/d based on an assumed figure of 2 percent ash in the wood (included would be any unburned carbon plus any debris retained in the wood fuel after processing).

   A pneumatic ash handling system would transfer bottom ash from the boiler and fly ash from the dust collection system to a storage container located outside the plant building for daily removal by truck. It would then be disposed of in a suitable landfill area away from the plant site. The study has assumed that the ash can be disposed of in the MacMillan Bloedel landfill site referred to in Section 2.1.

7. Site Services - A service building would be provided located adjacent to the thermal plant. This building would contain an administration office, warehousing and workshop areas to provide the necessary facilities and equipment such as air compressors, cranes and machine tools to operate and maintain the plant.

   Potable and fire protection water systems and sewage disposal facilities would be provided.

Construction power would be supplied by either a temporary line from Port Clements or by a mobile diesel generating unit.

4.7 STATION CONTROL AND POWER TRANSMISSION

(a) Station Control

The major components and auxiliaries of the plant would be supervised and controlled from the central control room. A conventional analog system would provide the operator in the central control room with all the process information and would automatically maintain the selected operating rate.

To provide sufficient load for a central thermal generating station on the Queen Charlotte Islands, the existing distribution systems at Masset and Sandspit would have to be joined by a new 69 kV transmission line. It is assumed that the existing diesel generating stations would be maintained on standby for emergency and future peaking requirements. This would eliminate the need for black-start facilities.

The generators would supply power to the main 69 kV transmission system and the station service. The steam turbines would be operated on speed control, through its isochronous governor system, to maintain the system frequency.

Electric power would be generated at 12.5 kV, 60 Hz. Approximately 90 percent of the power would be fed through a main transformer into a new 69 kV substation at Ferguson Bay and onto a tie-in at the Port Clements Substation. The Ferguson Bay substation (estimated at $790,000) and transmission line to Port Clements (estimated at $1,311,000) are included in the plant cost. The remaining 10 percent would be fed into the plant station service.

Protection and control equipment would be installed based on normally accepted practices for primary industries and utilities.

(b) Transmission

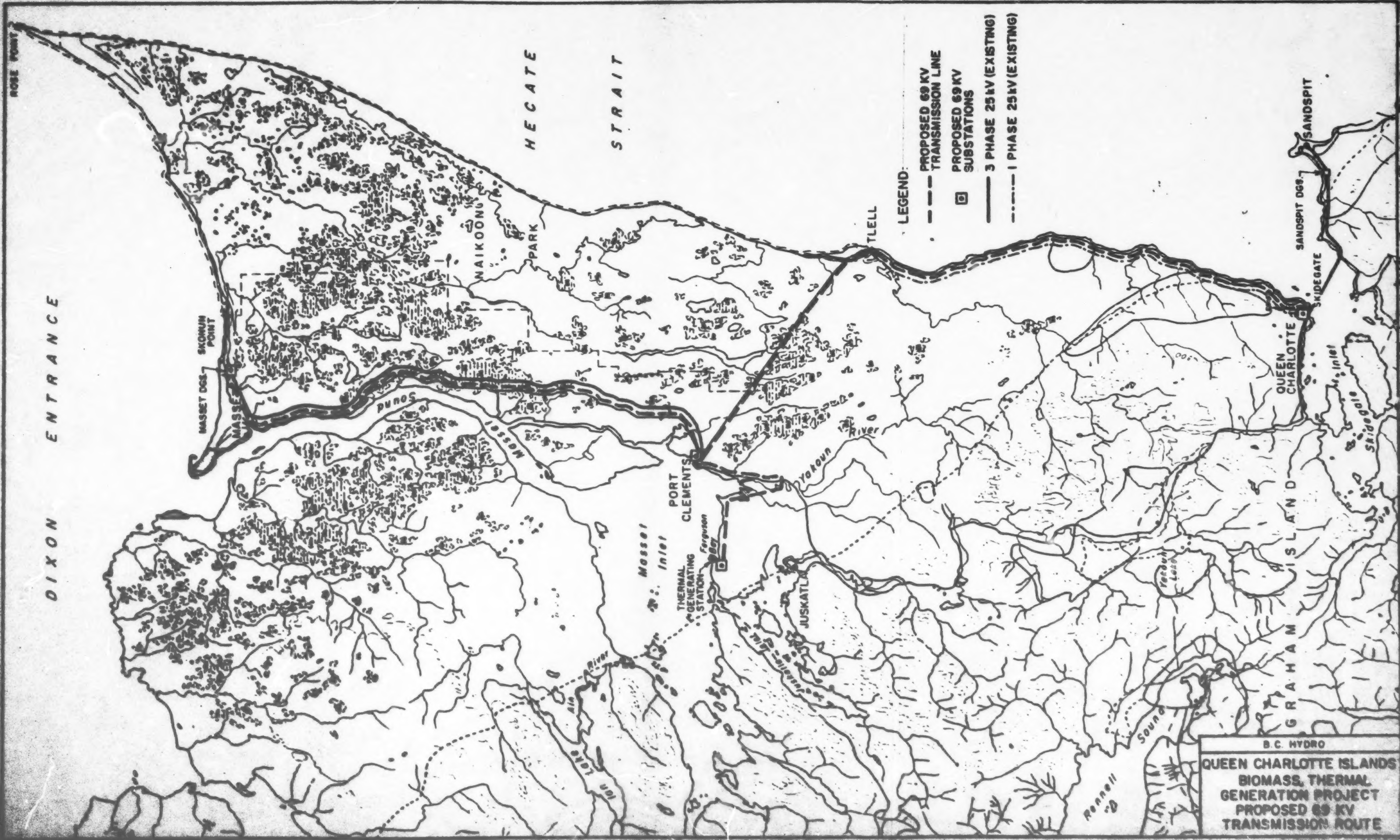
The new 69 kV transmission system would connect the substations at Masset and Skidegate, as shown on Fig. 4-3, through a central substation at Port Clements. The existing 25 kV distribution system would be left in place, including the 6 km submarine crossing to Sandspit. The cost of the 69 kV transmission system has been estimated as follows:[17]

69 kV Transmission Line	Length	1984 (k$)
Port Clements to Masset	45 km	$2,579
Port Clements to Skidegate	68 km	3,898
Total estimated transmission cost		$6,477

A new 69 kV transmission line (16 km long) from the plant at Ferguson Bay to the substation at Port Clements has been estimated to cost $1.311 million and has been included in the plant design cost estimate, to represent a typical transmission tie-in-cost.

(c) Substations

Preliminary estimates have been prepared for 69 kV substations at Port Clements, Masset and Skidegate.[18] It has been assumed that where possible existing surplus B.C. Hydro transformers are used. The new substation costs have been estimated as follows:



B.C. HYDRO

QUEEN CHARLOTTE ISLANDS
BIOMASS, THERMAL
GENERATION PROJECT
PROPOSED 69 KV
TRANSMISSION ROUTE

FIGURE 4-3

Substation	Description	1984 (k$)
Port Clements	Construct new 69 kV substation, terminate three 69 kV lines, and install three 69 kV circuit breakers	$1,070
Skidegate	Construct new 69/25 kV substation, terminate one 69 kV line and one 25 kV submarine cable circuit, install one 10 MV·A, 69/25 kV transformer (surplus B.C. Hydro), and install one 69 kV circuit breaker, two 25 kV circuit breakers and one 25 kV feeder position.	$ 840
Masset	Expand existing substation, install one 10 MV·A, 69/25 kV transformer (B.C. Hydro surplus), one 69 kV circuit breaker and one 25 kV circuit breaker.	$ 630
Sandspit	Expand existing substation, terminate one 25 kV submarine cable circuit, and install one 25 kV circuit breaker	$ 90
	Substation costs	$2,630
	Protection and communications	$ 263
	Total estimated substation costs	$2,893

This proposed 69 kV transmission scheme would be grounded only at the Ferguson Bay thermal plant transformer. With this transformer out-of-service, the 69 kV system would become ungrounded. Additional grounding points could be provided by purchasing new transformers for Skidegate and Masset at an additional cost of $300,000. A more detailed evaluation of the proposed thermal generating station would consider the merits of using new transformers and providing the extra grounding.

4.8 CAPITAL COST ESTIMATE

The capital costs, totalling $26M in June 1984 dollars for the 10 MW (2 x 5 MW) generating station are shown in Table 4-3. The figures were developed from manufacturers and consultants budgetary estimates for plant equipment, and from internal B.C. Hydro sources for civil, structural, electrical, substation, switchyard and transmission tie-in costs.

The costs include:

1. equipment supply, installation, freight, import duties and Federal and Provincial Sales Taxes where applicable;
2. plant indirect costs at 8 percent of total direct capital costs to cover the cost of a construction camp and any necessary construction related items;
3. plant engineering, procurement and construction management fees based on 8 percent of direct and indirect capital costs;
4. contingencies based on 20 percent of all direct, indirect and engineering costs.

The projected engineering and construction schedule is shown in Fig. 4-4 and forms the basis of the capital cost cash flow schedule in Table 4-4.

As discussed in Section 4.3 the capital costs were developed for alternative plant designs incorporating a single 10 MW (net) and five 2 MW (net) units. Capital costs estimates were obtained from both outside consultants and adaped from the base case plant costs, including the items noted above the capital costs shown in summary in Table 4-5 are:

1 x 10 MW = $22.3M
5 x 2 MW = $34.5M

TABLE 4-3

10 MW (2 x 5 MW) WOOD-FIRED THERMAL GENERATING STATION
CAPITAL COST ESTIMATE
(k$)

Mechanical		
1. Fuel Preparation and Feed System	$ 525	
2. Steam Boiler c/w Auxiliaries and Controls (including Flue Gas Cleaning)	4,600	
3. Turbine-Generator c/w Lube Oil System, and Controls	3,800	
4. Condenser and Cooling Water System	400	
5. Feedwater System including Deaerator and Feedwater Pumps	315	
6. Water Treatment Plant	85	
7. Piping and Insulation	400	
8. Ash Handling System	195	
9. Mobile Equipment	720	
Mechanical Total		$11,040
Electrical		
1. Plant Electrical	$1,120	
2. Substation and Switchyard	790	
3. Instrumentation and Controls (excluding Boiler Controls)	160	
Electrical Total		$2,070
Civil and Structural		
1. Site Improvements and Roads	$1,000	
2. Concrete and Structural Steel	3,690	
Civil and Structural Subtotal		$4,690
Freight and Duty (included above)		
Provincial Sales Tax @ 7%		800
Total Plant Direct Construction Cost		$18,600
Plant Indirect Construction Cost		1,500
Engineering, Procurement and Construction Management Fee		1,600
Total Cost		$21,700
Contingencies		4,300
TOTAL PLANT CONSTRUCTION COST		$26,000

10 MW WOOD FIRED THERMAL GENERATING STATION
CONSTRUCTION SCHEDULE

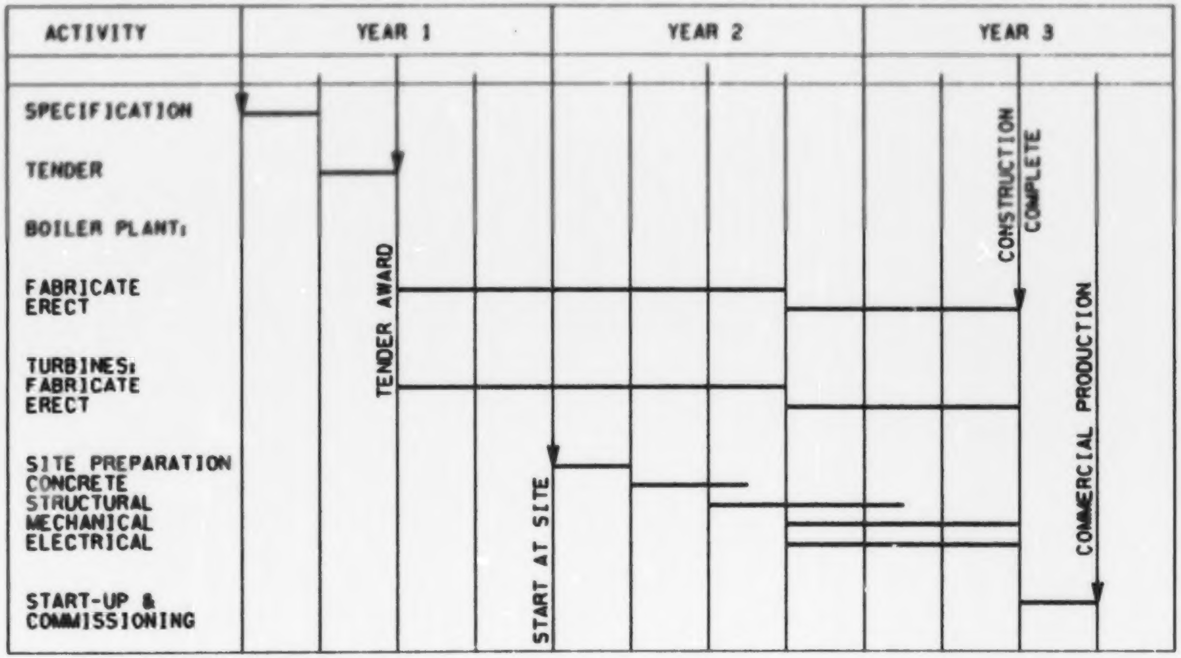


FIG 4-4

TABLE 4-4

10 MW (2 x 5 MW) WOOD-FIRED THERMAL GENERATING STATION CAPITAL COST CASH FLOW (k$)

Area	Year 1	Year 2	Year 3	Total
Mechanical	$500	$6,000	$5,200	$11,700
Electrical	-	700	1,400	2,100
Civil and Structural	-	3,350	1,450	4,800
Indirect Costs	-	750	750	1,500
Engineering and Construction	500	500	600	1,600
Transmission Tie-in			1,311	1,311
Subtotal	$1,000	$11,300	$10,711	$23,011
Contingencies	$200	$2,200	$1,900	$4,300
Total Cost	$1;200	$13,500	$12,611	$27,311

Note: Freight, duty and taxes included in equipment.

TABLE 4-5

10 MW WOOD-FIRED THERMAL GENERATING STATION
CAPITAL COST ESTIMATES - PLANT ALTERNATIVES
(k$)

	1 x 10 MW	5 x 2 MW
Mechanical	$9,500	$16,000
Electrical	1,700	2,700
Civil and Structural	4,000	5,000
Provinical Sales Tax	700	900
Total Plant Direct Construction Cost	$15,900	$24,700
Plant Indirect Construction Cost	1,300	2,000
Engineering, Procurement and Management	1,400	2,100
Total Cost	$18,600	$28,800
Contingencies	3,700	5,700
Total Plant Construction Cost	$22,300	$34,500

4.9 OPERATING AND MAINTENANCE COST ESTIMATE

The annual cost estimate to operate and maintain the 10 MW (2 x 5 MW) thermal plant is $1.79M as shown in Table 4-6. These direct costs in June 1984 dollars include:

1. Operating and maintenance labour based upon a manpower list shown in Table 4-7.
2. Cost of spare parts, supplies, lubricants and fuel oil for the generating station based on a percentage of fixed capital costs.
3. Costs of spare parts, supplies lubricants for the fuel preparation equipment based on a percentage of capital costs.
4. Cost of spare parts, supplies, lubricants and fuel for the mobile equipment in the log handling operations based on a unit cost operating hour basis.

TABLE 4-6

10 MW GENERATING STATION
OPERATING AND MAINTENANCE COST ESTIMATE

Area			Annual Cost
Log Handling:			
	Labour		$ 61,000
	Equipment and Supplies*[1]		61,000
		Subtotal	$ 122,000
Fuel Preparation:			
	Labour		$ 155,000
	Equipment and Supplies*[1]		263,000
		Subtotal	$ 418,000
Thermal Plant:			
	Labour		$ 760,000
	Materials and Supplies*[2]		490,000
		Subtotal	$1,250,000
	Total Operating and Maintenance		$1,790,000

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*[1] Includes mobile equipment.

*[2] Includes allowance for annual maintenance contract.

TABLE 4-7

10 MW WOOD-FIRED GENERATING STATION
OPERATING MANPOWER

Administration	Number Required	Annual Salary
Plant Superintendent	1	$55,000
Steno Clerk	1	$25,000
Fuel Preparation		
Machine Operator	2	$33,000
Equipment Operator	2	$33,000
Helper	3	$28,000
Generating Station		
Senior Operator	5	$35,000
Auxiliary Operator	5	$33,000
Helper	5	$28,000
Fuel Handling	2	$30,000
Maintenance		
Mechanic	2	$35,000
Electrician	2	$35,000
Total Required Manpower	30	

SECTION 5.0 - WOOD GASIFICATION POWER GENERATION

5.1 STUDY SCOPE

Since generation of power using low-Btu gas fuel produced by biomass gasification is still not a fully proven technology, a commercial or demonstration stage of development is needed before proceeding with a detailed design. Several gasifiers have reached commercial production levels and are being used successfully to produce gas for boilers, hot oil heating systems and direct heating applications. Also, several diesel and gas turbine engine manufacturers have modified engines to operate on low-Btu wood gas. A reasonable amount of success has been indicated in combining the biomass gasification with engine generation of power especially in Germany, France and Finland. However, production, separation and disposal of oils and tars generated with the wood gas is still a major problem. A biomass gasification-engine generating system status review has been carried out as part of this study to determine a timeframe for commercial application of the technology.

For this study a wood gasification power generating station concept has been developed. The new 10 MW centralized generating station has been designed to supply the near-term forecast load, exclusive of new industrial demand, for the Queen Charlotte Islands. Included in the design is power transmission, wood residue collection and fuel processing facilities as designed for the conventional thermal generating station but adapted to suit the requirements of the wood gasification system. Basic plant design parameters, layout and offsite facilities have been developed within B.C. Hydro with input and quotations from the equipment manufacturers.

5.2 STATUS REVIEW

As indicated in Table 4-1, the combination of a wood gasifier with an internal combustion engine generating set is considered to be a near commercial technology. The components are commercially available but there are problems associated with their combined use for power generation.

The evaluation of systems using an internal combustion engine coupled to a gasifier is presently hampered by the lack of test data for the contaminants in the fuel gas, particularly tar and particulate, and the lack of operating data for an engine operated on such a fuel. It is presently only possible to identify obvious potential problems such as tar deposition in intake manifolds and supply piping. Long-term effects of contaminants on lubricating oil, cylinder wear and carbon deposition on the cylinder head are not known.

Although several gasifier manufacturers are interested in or developing systems with internal combustion engines, few are presently marketing these systems.

Some very limited testing of firing a low-Btu gas in a gas turbine has been done. Because of the lack of data on the content of contaminants in fuel gas from a wood gasifier, it is presently not possible to state with any certainty what problems might be encountered with a gasifier/gas turbine combination. Corrosion and fouling problems are likely unless extreme attention is payed to gas cleanup. Advanced Energy Applications, Inc. (California) has been working on combining a gasification system (Sur-Lite Corp.) with a 1250 kW gas turbine (Turbo Energy Systems, Inc.) and has provided a cost estimate of about $1200/kW (U.S.) for a system. A 2-year demonstration program was estimated to cost about $2.5 million to $3.0 million (U.S.).[2]

Lamb-Cargate and General Electric recently designed a gasifier and gas turbine generating system. The system consists of two 106 GJ/h Wet Cell Burners which feed a 10 MW, Frame 3 GE gas turbine generating unit.[5] The station would consume 16 ODT of waste wood per hour at peak load. A turnkey installation is estimated to cost $2200/kW (1982 Canadian dollars). A gasifier has been used in demonstration applications for direct-fired kiln drying and to produce steam, but it has not been used in conjunction with an electrical generating plant.

Aerospace Research Corporation (Virginia) has adapted an Allison 501 KG gas turbine engine to operate on hot gases from a combustor-fired with pulverized wood. The combustion gases are scrubbed in a series of cyclones and are fed directly into the turbine without causing any significant blade erosion. A 3000 kW generating unit is being installed at Red Boiling Springs, Tennessee. The 90 t/day of surplus sawdust fuel will be supplied by local sawmills at $7.17/t (Can.) ($5/green ton (U.S.)) and the Tennessee Valley Authority will buy the power for 10 years at 3.4 to 3.6 mills/kW·h. The entire plant will cost less than $2 million (1984 U.S. dollars).[4]

Considering the advantages and disadvantages of the various prime movers for gasifier generating systems, internal combustion engines are preferred. The engine may be of either single-fuel or dual-fuel design, the preference depending on the system reliability that is needed to satisfy the power generation demands. If high reliability is essential, then a dual-fuel engine should be used.

Downdraft gasifiers are preferred for power generation systems of less than 1 MW output capacity. Larger systems could be assembled using a modular design. Although several problems have been encountered by operating systems, a downdraft gasifier is superior in this size range because of the low tar content of the fuel gas. This reduces gas cleanup difficulties, reduces problems with disposal of tar contaminated scrubber water and reduces tar deposition in the engine.

The Imbert gasifier and Duetz (KHD) diesel generating set combination is one of the more advanced downdraft systems available, with a relatively successful operating history.[4] A 128 kW wood gasification-engine generating system is installed and in operating order at Fort Providence, Northwest Territories (Sieg O. Phillips, Snowshoe Inn, personal communication). This system is believed to be one of the only systems in Canada that is installed and available for operation. The system is presently maintained as standby power because the operating expenses for such a small system makes the energy costs higher than diesel fuel generated power. A 3 MW system, consisting of four gasifiers and gas engine generator sets rated at 685 kW_e each, would cost approximately $4.6 million (Can.) with a 16-month delivery.[3]

For systems above 1 MW, updraft gasifiers could be used, possibly up to output capacities over 2 MW, but the high tar content of the fuel gas makes them relatively unattractive compared to fluidized bed gasifiers.

For systems over 1 MW, fluidized bed gasifiers are preferred. Considerable work is needed to develop a power generating system using a fluidized bed gasifier due to the gas cleanup and system control problems. The limited data that is presently available indicates that less tar will need to be removed from gas from a fluidized bed unit than from an updraft unit. One of the more advanced fluidized bed gasifiers is manufactured by Omnifuel Gasification Systems, however, it has not been used to provide fuel for an engine generating set to date.

Omnifuel Gasification Systems is a joint venture formed by Omnifuel Gasification Systems Ltd., Ontario Energy Corporation and Canertech Inc. They have designed a complete wood gasification package which consists of an air blower and drive motor package, start-up heater, reactor vessel, air distributor, complete feed system, pair of cyclones, heat exchanger, ash handling system, flare stack, insulation, refractory liner and a complete gas scrubbing system. This system is suitable for producing a low-Btu gaseous fuel.

The Omnifuel plant is available in commercial sizes as large as 24 MW (thermal).[6] This is the largest gasifier in the world that uses wood as a fuel. A commercial, demonstration gasifier is installed in a plywood mill at Hearst, Ontario where the product heat was used in the dryers. The gasifier was installed in February 1981 and it had been operating since May of that year. Installation was completed within 8 months of ordering the unit. Unfortunately, the gasifier was shutdown in late 1983 because the operating economics were no longer favourable and the majority of the mill residue fuel became more valuable as pulp chips than as fuel.

Wartsila (Finland), a company that makes diesel engines under licence from Pieltstick, has expressed an interest in using the Omnifuel gasifier with a new 2400 kW engine that they built for operation on low-Btu gas. During 1982 the engine was satisfactorily tested using a gasifier built by Ahlstrom and fuelled with peat.[10,11]

Gasifier systems could be completely automated and, thus, require less supervision than steam systems. Dual-fuel engines are very attractive for systems where a backup fuel is needed to ensure continued power generation.

Several small gasifier power generating systems are being designed, fabricated and tested to meet the requirements of remote community power generation but none to date have been tested. Some of the systems approaching a demonstration stage of development include:

1. The Alaska Village Electric Cooperative (AVEC)[7,8] project using a Biomass Corporation, California (3 10^6 Btu/h) downdraft gasifier coupled to a Caterpillar G 353 (natural gas, spark ignited) engine generating set rated at 225 kW was set up to be demonstrated at the Mitkof Lumber Company, Petersburg, Alaska. The demonstration unit was tested in Anchorage Alaska and the data was

thoroughly evaluated. The unit was never installed at the Mitkof lumber site as planned, and discussions with Bonneville Power Administration may result in the unit being sent to the Pacific Northwest for demonstration.

2. The Heuristic Gasifier (B.C.) has been designed and fabricated to provide a low tar gas fuel suitable for use in a spark ignition gas engine. The two-stage 3.10^{6} Btu/h gasifier is completed and is awaiting additional funding for the operational testing of the unit.

3. Petro-Sun Inc. (Ontario) has manufacturing a three-chamber cross-draft gasifier, to be used with a diesel engine-generator set. The system is complete and will be tested in the Petro-Sun plant for 1 year before being demonstrated in the remote northern Ontario community of Ramsey (a logging camp operated by E.B. Eddy Forest Products Ltd.).

Although more emphasis is being put into wood gasification power generation demonstration projects, there are no fully successful commercially available wood gasification power generation systems available at this time. The Imbert gasifier coupled to a Deutz diesel generating set is one of the more complete commercially available units but even after several years of demonstration the system cannot be left to operate unattended. The automatic wood feed and ash removal systems tend to plug up or bridge, and oils and tars carried over in the fuel gas foul the engines. It is expected that at least another 5 to 10 years of development will be necessary before wood gasification power generation systems will break into mainstream power generation and be reliable.

5.3 PLANT DESIGN AND OPERATION

For the purpose of this study, a conceptual plant design has been based on an Imbert power generation package.[3] As for the thermal generating station, the wood gasification power generation plant has been based on the load growth projection given in Section 1.4. The design is thus based on the supply of 45.54 GW·h at a peak load of 9.47 MW in 1994/95.

The station is assumed to operate 8760 h/a, with the existing diesel generating stations being used for standby emergency service. The wood waste fuel quality is the same as outlined for the thermal generating station (Section 4.2). The fuel supply schedule and fuel preparation operations are also assumed to be the same as for the thermal generating station.

The plant layout would similarly be located on Echinus Point on a 3 ha site, as shown on Fig. 5-1. Because of the nature of the wood gasification power generation system boiler water treatment and condensor cooling will not be required, and the operators would not have to be qualified steam plant operators.

5.4 WOOD FUEL PREPARATION

The gasification process requires clean wood fuel free of stones and clay, otherwise the ash in the gasifier becomes slag and disturbs the gasification process. The raw wood waste is first cut to lengths of 1.50 m to 2.50 m. The wood residues must then be reduced in size to less than 70 cm in length and 150 cm^3 per piece. Hydraulic cutters, drum chippers and/or hogging machines can be used.

The pre-dried wood chips are then stored near the gasification plant under cover on a hard surface in order to minimize contamination by mud and gravel, and also to protect the dry wood from rain. Dry storage for 5 days operation will provide a feedstock supply sufficient for weekend and emergency operation.

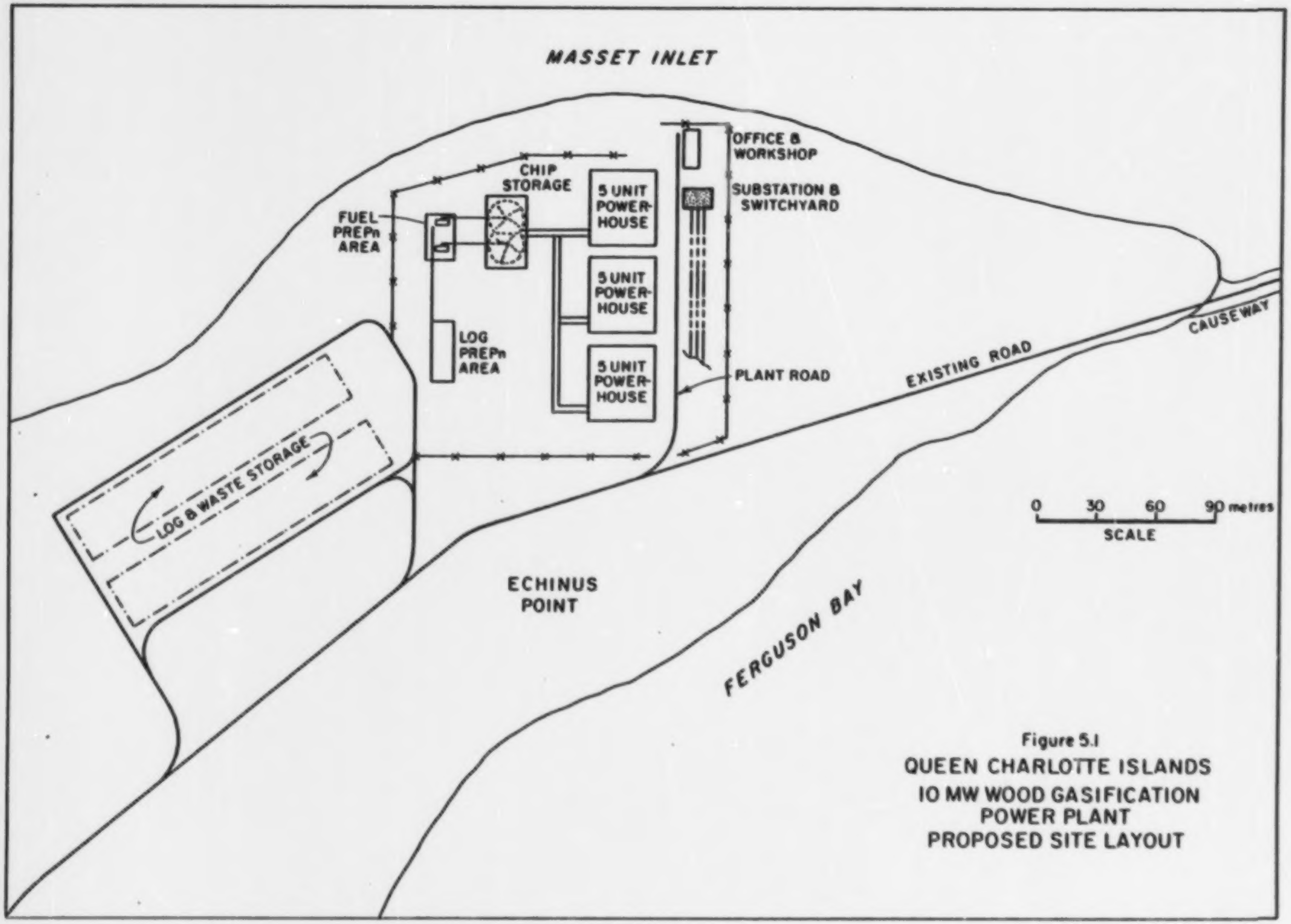


Figure 5.1
QUEEN CHARLOTTE ISLANDS
10 MW WOOD GASIFICATION
POWER PLANT
PROPOSED SITE LAYOUT

The feed hopper of the gasification plant can be equipped, if required, to use the exhaust gas from the gas engine to reduce the moisture content of the wood. Connecting pipes from the engine to the feed hopper are provided.

5.5 WOOD GASIFICATION POWER GENERATION PLANT OPERATION

(a) Gasifier

The gasifier is fed by a hopper and conveyor, which are installed at the front of the gasifier in an underfloor pit. The fuel is transported from the hopper to the gasifier automatically to match the gasifier consumption and balance the gas requirements of the engine. The IMBERT Wood Gasifier operates at negative pressure resulting from the suction of either the gas engine or a gas blower.

The special construction of the IMBERT Gasifier allows automatic rapid adjustment of gas production to match the operating conditions such that only the gas required by the engine is produced. The wood fuel moves through the gasifier by gravity.

After start-up it takes about 5 minutes for gas production to begin, and within 20 minutes gas production is up to full capacity. The intake air is preheated by the product gas. In the continuous gasification process, the wood fuel dries, carbonizes to charcoal and is gasified with insufficient air. The charcoal partly oxidises with the incoming air to carbon monoxide (a combustible gas) and also partly to incombustible carbon dioxide. However, some carbon dioxide is reduced in the high temperature charcoal bed to carbon monoxide increasing the amount of combustible gas produced.

In the down-draft gasification process the carbon dioxide stream from the drying zone and the products from the pyrolysis zone must pass through the high temperature charcoal bed. The gasifier is designed such that even at 25 percent of design throughput, sufficiently high temperatures are produced that cracking of all heavy hydrocarbons such as phenols and tars takes place giving a gas practically free of tar. At such high temperatures steam partly reduces to hydrogen and oxygen. The released oxygen combines with carbon to produce more carbon monoxide. In addition a small amount of methane is produced. The resulting hydrogen, carbon monoxide and methane are the combustible components of the resulting low-Btu gas.

The lower heating value of the gas when using air-dried wood is between 4830 - 5460 kJ/Nm^3 (130 - 150 Btu/scf). Dry hardwood and dry softwood both result in the same quality and quantity of gas.

A starting blower, flare and automatic electric ignitor are provided for start-up of the gasifier. The start-up time varies with the size of the gasifier. To shut down the gasifier, the engine or the blower has to be turned off. If an appropriate temperature has already developed and is maintained in the gasifier bed, gasification restarts immediately after restarting the suction blower, even after long breaks.

In the gasification process a part of the ash is discharged with the gas flow. Most of the ash and also some fine charcoal falls down into the ash collection chamber, through the lower grate of the gasifier. Normally the grate is moved from time to time by mechanical means to facilitate the removal of the ash. The ash is readily removed through a gas-tight service opening. Automatic ash removal is being developed. The ash will be disposed of in a local landfill site.

After gasification the product gas passes through a dust separator. If required, a heat exchanger can be installed to recover heat for fuel drying. The pre-cleaned gas passes through a washer to reduce the temperature below the dew point. Clean water at a pressure of five bars is required for the scrubbing process. As the constituents which might pollute the environment have been removed during the gasification process, the condensate and ash/mud can be drained into the waste water system.

An electrostatic filter provides final cleaning of the fuel gas. In this equipment all tiny water drops and any fine dust entrained by the gas flow are removed.

Suitable instrumentation and control devices guarantee a continuous and essentially automatic operation.

(b) Gas Engine Generator Set

The life of combustion engines depends on the compression ratio, the rotational speed of the engine and the quality of the fuel. According to the mechanical performance testing, the thermal efficiency of the engine generator is 29 to 31 percent.

Experience gained from operation of wood gasification power plants has shown that loading the plant in steps up to 15 percent of the installed capacity can be carried out without any difficulties. It has also shown that such plants can operate alone or in parallel with a central plant.

(c) Energy Balance

The typical energy balance from 1 kg of air-dried wood (20 percent moisture content by weight) is as follows:

Gasifier

IN:	1 kg air-dried fuel	14 700 kJ	4.07 kW·h	100.0%
OUT:	Chemical energy after gasification			
	(2.3 Nm^3 x 4830 kJ/Nm^3)	11 110 kJ	3.08 kW·h	75.5%
	Heat from gas cooling	820 kJ	0.22 kW·h	5.5%
	Total Usable Energy	11 930 kJ	3.30 kW·h	81.0%

Gas Engine

IN:	Chemical gas energy	11 110 kJ	3.08 kW·h	100.0%
OUT:	Mechanical engine performance	3330 kJ	0.92 kW·h	30.0%
	Heat from cooling water	3330 kJ	0.92 kW·h	30.0%
	Heat from exhaust gases	3330 kJ	0.92 kW·h	30.0%
	Heat loss (radiation)	1120 kJ	0.32 kW·h	10.0%

Electric Generator (150 kV·A type)

Mechanical engine performance	3330 kJ	0.92 kW·h	100.0%
Generator output (0.8 pf)	3030 kJ	0.84 kW·h	91.0%

(d) Wood Fuel Consumption

Based on the typical energy balance wood fuel consumption per kW·h (full load with suction engine operation) is:

1.0 / 0.84 = 1.19 kg wood (20% moisture by weight)/kW·h

As the efficiency of different units will vary depending on size and load requirements, an average consumption of air-dry wood can be considered to be 1.25 kg. Therefore the fuel requirement for a 10 MW plant generating 45.54 GW·h/a would be 57 000 air-dried tonnes/year or 47 500 ODt/a.

(e) Low-Btu Gas Composition

The typical gas composition of the output of an IMBERT gasifier operating on European wood (analysis made by the Ruhrugas-Laboratory) is as follows:

Air Intake Nm^3/h		300	400	450
Gas Output Nm^3/h		450	625	720
Gas Analysis Volume (%)	CO_2	4.49	10.01	12.80
	O_2	0.43	0.96	0.01
	N_2	52.47	50.49	49.29
	CO	28.77	20.53	18.74
	H_2	11.91	16.45	18.52
	CH_4	1.76	1.47	1.50
Other Components: (in volumetric parts per million)				
	C_2H_6	155	135	203
	C_2H_4	324	588	976
	C_2H_2	1	1	1
	C_3H_8	9	3	8
	C_3H_6	40	33	57
	C_4H_{10}	1	1	1
	C_4H_8	4	2	4
	C_4H_6	6	7	13
	C_5H_{12}	1	1	1
	C_6H_{14}	1	1	1
	C_6H_{16}	1	1	1
	C_8H_{18}	1	1	1
	C_9H_{20}	0	0	0
	Xylole	2	1	3
	$C_{10}H_{22}$	0	0	0
	$C_{11}H_{24}$ a. high.	0	0	0
	Benzol	118	119	158
	Toloul	9	6	21
Totals		668	894	1443
Volume (%)		0.007	0.009	0.014

5.6 WOOD GASIFICATION POWER GENERATION PLANT

The plant buildings, as shown in Fig. 5-2, will be designed to contain a 10 MW IMBERT wood gasification power generation system consisting of 15 identical power trains including the following:

(a) IMBERT Gasifier System

15 IMBERT feeding system (Type 10 000)

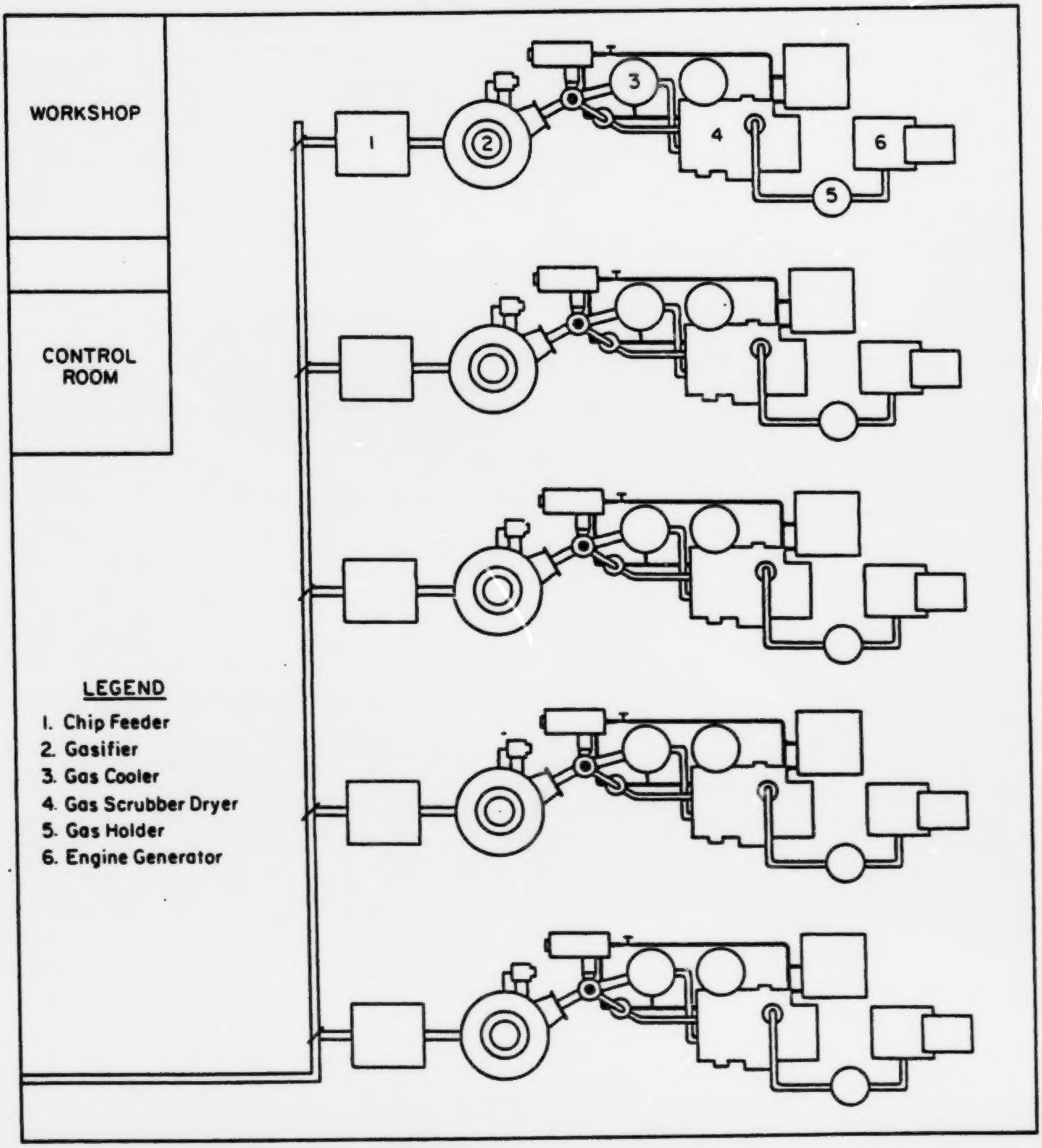
- For continuous transfer of wood fuel from the day hopper to the head of the gasifier.
- Equipped for use of the exhaust gas from the gas engines to dry the wood fuel.
- To be mounted on an underfloor foundation.

Volume of the day hopper	10 m^3
Feeding interval at full load	4 h
Installed electric capacity for hydraulics	15.0 kW
Installed electric capacity for conveyor	1.5 kW

15 IMBERT wood gasifiers (Type 1.880)

- For operation on air-dry wood fuel with a maximum moisture content of 25 percent by weight.
- Inner jacket and parts exposed to high temperature (alloyed steel).
- Gasifier head with airlock feed compartment and safety vent.
- Level indicator for fuel (connected to the fuel supply system).
- Gasifier hearth, (equipped with air preheating).
- Mechanically actuated grate with electric/motor drive.
- Ash collection chamber under the grate with mechanical ash removal and ash containers.
- Instrumentation for indicating gas temperature and alarm equipment for maximum gas temperature.

Figure 5.2
TYPICAL 5 UNIT
WOOD GASIFICATION
POWER PLANT



Nominal gas volume	1880 Nm^3/h
Minimum gas load	470 Nm^3/h
Nominal wood consumption	822 kg/h
Minimum wood consumption	206 kg/h
Installed electrical capacity	2.75 kW
Power consumption full load	50%
Ash container appr. 110 L volume	2

15 IMBERT dust separator (Type 1.880/11)

Installed electric capacity	1 kW
Ash containers appr. 110 L volume	2

15 IMBERT gas coolers, (Type 1.880)

Installed electric motor capacity	3.5 kW

8 IMBERT water cooling towers (Type 1.880)

15 IMBERT electrostatic filters (Type 1.880)

High voltage equipment appr.	25 000 V/25 mA
Installed electric motor capacity	1.5 kW

15 IMBERT gas blowers (Type 990/500)

- For plant start-up.
- Flare with electric ignition.

15 sets Valves, pipe and fittings for connection of the above components

1 Switchboard and panels for the above equipment (Type 1.880/4)

(b) IMBERT Gas Engine Generator System (15 x 685 kW/60 Hz)

15	IMBERT wood gas engines	MWM G 441
	Engine speed	900 rpm
	Cylinders	16
	Compression ratio	10:1
	Bore (mm)	230
	Stroke (mm)	270
	Cylinder displacement (litre)	179.48
	Mechanical power with IMBERT - gas + - 5%	721 kW
	Alternator output	685 kWe

	Ambient temperature	302 K
	(or equivalent engines)	
	-With dry air filter, air gas mixer, airstart	
	-High voltage ignition system	
	-Lubricating oil package	
	-Flywheel	
	-Governor control	
	-Safety controls for automatic shutdown	
	-Exhaust gas manifolds (water cooled)	
	-Silencer 25 db	
	-Instrument panel and controls:	
15	Radiator assemblies	
1 set	Exhaust gas pipes from the engine to the silencers and to the day hopper	
15	Alternators (self-regulated, brushless)	856 kV·A
	Power output at 0.8 power factor	685 kWe
	Voltage	400 V
	Frequency	60 Hz
	Speed	900 rpm
1	Air compressor package	
	For engine starting and control	
15 sets	Protection and control switchboards, panels and switchgear for plant operation and synchronizing	

The switchboards and control panels are designed as for conventional power stations, with manual or automatic synchronization, and with the necessary control and warning devices.

Prefabrication of the plant:

The whole plant is constructed as prefabricated modules.

5.7 SITE SERVICES

As for the thermal generating station, a service building will be provided adjacent to the powerplant. This building will contain the office, warehouse, and workshop areas to provide the necessary facilities and equipment required to operate and maintain the plant.

Potable and fire protection water systems, sewage disposal, facilities site power and construction power will be provided as required. It is assumed that suitable quantities and quality of water will be available from wells.

5.8 TRANSMISSION REQUIREMENTS

The transmission system upgrading will be identical to that proposed for the thermal generating station. It would include integration of the existing diesel generating system distribution grids by a 69 kV transmission line, with a connection provided to the new generating station. The system capital and operating costs would be the same as detailed in Section 4.6.

5.9 CAPITAL COST ESTIMATES

The capital cost estimate for the 10 MW wood gasification power generating station, shown in Table 5-1, is based on a quotation received from IMBERT Energietechnik GMBH & Co.KG.[3] Civil, structural, electrical, substation, switchyard and transmission costs have been based on the figures derived for the thermal plant, adapted to suit the gasification plant requirements.

The projected engineering and construction schedule is shown in Fig. 5-3 and forms the basis of the capital cost cash flow schedule in Table 5-2.

TABLE 5-1

10 MW (15 x 685 kW) WOOD GASIFICATION POWER GENERATING STATION CAPITAL COST ESTIMATE (k$)

Mechanical			
1.	Fuel Preparation and Feed System	$ 525	
2.	IMBERT Power Plant	15,105	
3.	Piping	200	
4.	Ash Handling System	123	
5.	Mobile Equipment	720	
	Mechanical Total		$16,400
Electrical			
1.	Plant Electrical	$560	
2.	Substation and Switchyard	790	
3.	Instrumentation and Controls (excluding Boiler Controls)	160	
	Electrical Total		$1,510
Civil and Structural			
1.	Site Improvements and Roads	$1,000	
2.	Concrete and Structural Steel	3,690	
	Civil and Structural Subtotal		$4,690
Freight and Duty			200
Provincial Sales Tax @ 7%			1,100
	Total Plant Direct Construction Cost		$23,300
Plant Indirect Construction Cost			1,800
Engineering, Procurement and Construction Management Fee			2,000
	Total Cost		$27,100
	Contingencies		5,400
	TOTAL PLANT CONSTRUCTION COST		$32,500
	Transmission Tie-in to Port Clements		1,311
	TOTAL STATION CONSTRUCTION COST		$33,811

Figure 5-3

10 MW (15 X 685 kW) WOOD GASIFICATION POWER PLANT CONSTRUCTION SCHEDULE

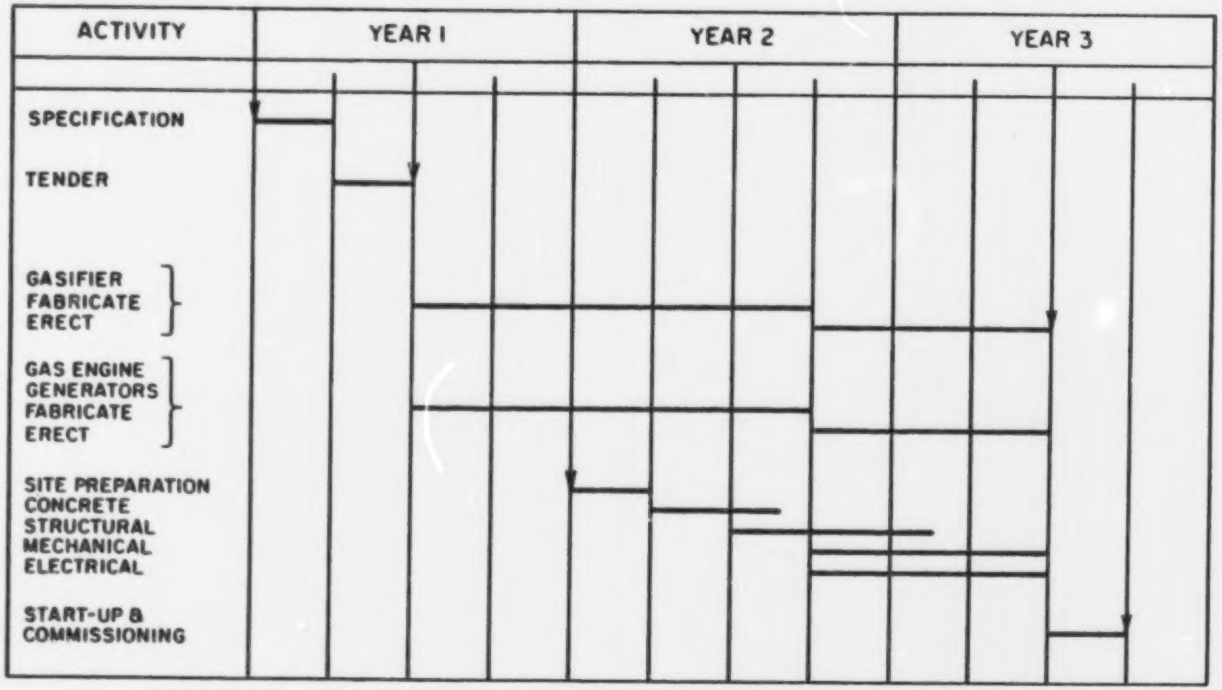


TABLE 5-2

10 MW (15 x 685 kW) WOOD GASIFICATION POWER GENERATING PLANT CAPITAL COST CASH FLOW (k$)

Area	Year 1	Year 2	Year 3	Total
Mechanical	$750	$8,850	$7,900	$17,500
Electrical	-	600	1,000	1,600
Civil and Structural	-	2,850	1,350	4,200
Indirect Costs	-	900	900	1,800
Engineering and Construction	500	700	800	2,000
			1,311	1,311
Subtotal	$1,250	$13,900	$13,261	$28,411
Contingencies	$ 250	$ 2,800	$ 2,350	$ 5,400
Total Cost	$1,500	$16,700	$15,611	$33,811

Note: Freight, duty and taxes included in equipment.

5.10 OPERATING AND MAINTENANCE COST ESTIMATE

The annual labour cost to operate and maintain the plant has been based on a three-shift operation estimated by the manufacturer at 3 to 3.5 percent of the total capital cost. However, the manpower requirements are essentially the same as for the thermal plant. The gasification plant operators do not have to be qualified steam plant operators and thus the diesel station operators would be qualified to operate the plant with a minimal amount of training. The gasification plants do not have to be supervised continuously, although some staff is required for operation of the combustion engines, and for fuel preparation and handling. At this level of estimating it can be reasonably assumed that the total annual operating and maintenance costs would be as outlined in Table 4-4, the same as for an equivalent thermal generating station.

SECTION 6.0 - ENVIRONMENTAL AND SOCIO-ECONOMIC OVERVIEW

6.1 GENERAL

B.C. Hydro has carried out an overview assessment to identify environmental and socio-economic impacts of the proposed wood waste-fired thermal generating station. Information about the site and surrounding area was obtained by direct observation, from discussion with local individuals[*1] and from the previous Juskatla Narrows tidal study.[16] MacMillan Bloedel Ltd. provided data on the area under study, adjacent to their Ferguson Bay dry land sort, which is the terminus for wood harvested in the Juskatla area.

Note: [*1] Notes on these interviews and information exchanges are on file for further reference if required.

6.2 SOCIO-ECONOMIC CONDITIONS

(a) General Description

Communities and Indian bands on Graham Island (Fig. 3-1) were the main focus of the socio-economic overview study; in particular Juskatla, Port Clements, Tlell, Queen Charlotte City and Sandspit (Moresby Island). The Haida Indian communities at Masset and Skidegate also are located within in the study area.

The Haida Indians were the original inhabitants of the Queen Charlotte Islands and archaeological evidence suggests that inhabitation dates back to 6000 B.C. Euro-Canadians did not settle in the Queen Charlotte Islands until the mid 1800s. At the last official census (1981) the total population of the Queen Charlotte

Islands was about 5400 persons of which about 30 percent were Indians.

Regional administration of the Queen Charlotte Islands is provided by the Skeena-Queen Charlotte Regional District in Prince Rupert. The only incorporated municipalities on the islands are Masset and Port Clements.

(b) Economic Base

The major economic base of the Queen Charlotte Islands is logging; the principal companies are Crown Forest Products, MacMillan Bloedel, Rayonier and Cipa. There are a few locally-owned wood processing plants but most of the raw logs are shipped elsewhere for processing. The standing timber resources of the Queen Charlotte Islands represent about 8 percent of the British Columbia total.

Commercial fishing and tourism represent significant seasonal activities and there are small amounts of agriculture (vegetables, berries) and manufacturing (wood production, fish processing).

A number of development opportunities exist which could expand and diversify the economy of the Queen Charlotte Islands. Consolidated Cinola Mines Ltd. have completed a feasibility study of a large gold mining prospect south of Port Clements. Offshore oil and gas exploration in Hecate Strait could occur within the next 10 years.

(c) Communities

Masset, which is at the northern end of Graham Island, is the largest community on the Queen Charlotte Islands (1981 population, 1569). Access to Masset is via highway and ferry from Sandspit (airport), ferry (Prince Rupert to Skidegate) and float aircraft, tug or barge service from Prince Rupert. The main economic base is commercial fishing and the B.C. Packers cannery. The Canadian Armed Forces have a base in Masset which employs 200 military personnel and 60 civilians. Masset appears to have good potential for tourism development. The Indian community of Haida is located near Masset.

Queen Charlotte City is located at the southern end of Graham Island (1981 census population, 1070). The principal economic base is logging and commercial fishing. The Indian community of Skidegate is located nearby and is the terminus for B.C. Ferry service from Prince Rupert.

Sandspit (1981 population, 754) is located at the northeastern end of Moresby Island and has the only major airport on the Queen Charlotte Islands. The main sources of local employment are the Federal Ministry of Transport and Crown Forest Products. Sandspit has been suggested as a likely base for offshore oil and gas exploration.

Tlell is a small rural community of 100 people on the eastern side of Graham Island. There is some agricultural and ranching activity there.

Port Clements (1981 population, 380), the closest community to the proposed generation site is located on Masset Inlet about 50 km south of Masset, about 27 km by road from Ferguson Bay. The community began as a mining town in the early 1900s but is now mainly a settlement and service community for MacMillan Bloedel's nearby logging operations based at Juskatla which is about 12 km southwest of Port Clements. The community of Port Clements would probably become the base for the proposed Consolidated Cinola gold mine, should it proceed. Port Clements also appears to have some prospects for tourism development.

The main Haida Indian communities on Graham Island comprise Haida (north of Masset) and Skidegate (east of Queen Charlotte City). As with other Queen Charlotte Islands' communities, employment is mainly in either logging or fishing. The total population of the Masset and Skidegate Indian bands was 1589 in 1983. The Haida are noted for their Indian artwork and carvings, and many artists are still active on the reserves.

People on the Islands generally share a strong identification with the Queen Charlottes and appear to be polarized in their attitude toward development. Even those that recognize the advantages of tourism or mineral development, are cautions and want to ensure that all environmental and social considerations are taken into account.

(d) Heritage Sites

Habitation of the Queen Charlotte Islands began sometime before 6000 B.C. These people established campsites where they subsisted primarily on shellfish. By 1500 B.C. semi-permanent village sites had been established and tools of ground stone and bone were in use. From 1500 B.C. to 1774 A.D. (the date of first contact with European explorers) the archaeological record is that of the ancestors of the Haida people. Euro-Canadian habitation of the Queen Charlotte Islands began in the mid 1800s.

A number of archaeological sites exist in the vicinity of Ferguson Bay and Juskatla Inlet. Site Fkub5 is located on the northeast shore of Ferguson Bay, close to the proposed thermal plant. The site consists of piles and linear arrays of fire cracked rock and may indicate a small aboriginal village. Another site Fkub8 is located 1 km east of Ferguson Bay on both sides of a logging road. This site consists of various types of stone tools and has been disturbed by road construction.

6.3 ENVIRONMENTAL FEATURES

(a) Aquatic Environment

The site selected for the project is located on the south shore of Masset Inlet on Echinus Point (Fig. 6-1). The inlet has an abundance of marine life. Masset Inlet and its tributary streams are utilized by several anadromous fish species including Pacific salmon (pink, sockeye coho, chum and chinook), sea-run cutthroat trout, steelhead and sea-run Dolly Varden char. Several varieties of clams are found along the south shore of Masset Inlet. Blue mussels, oysters and Dungeness crab are also abundant. Large intertidal areas supporting various benthic organisms are found near Ferguson Bay.

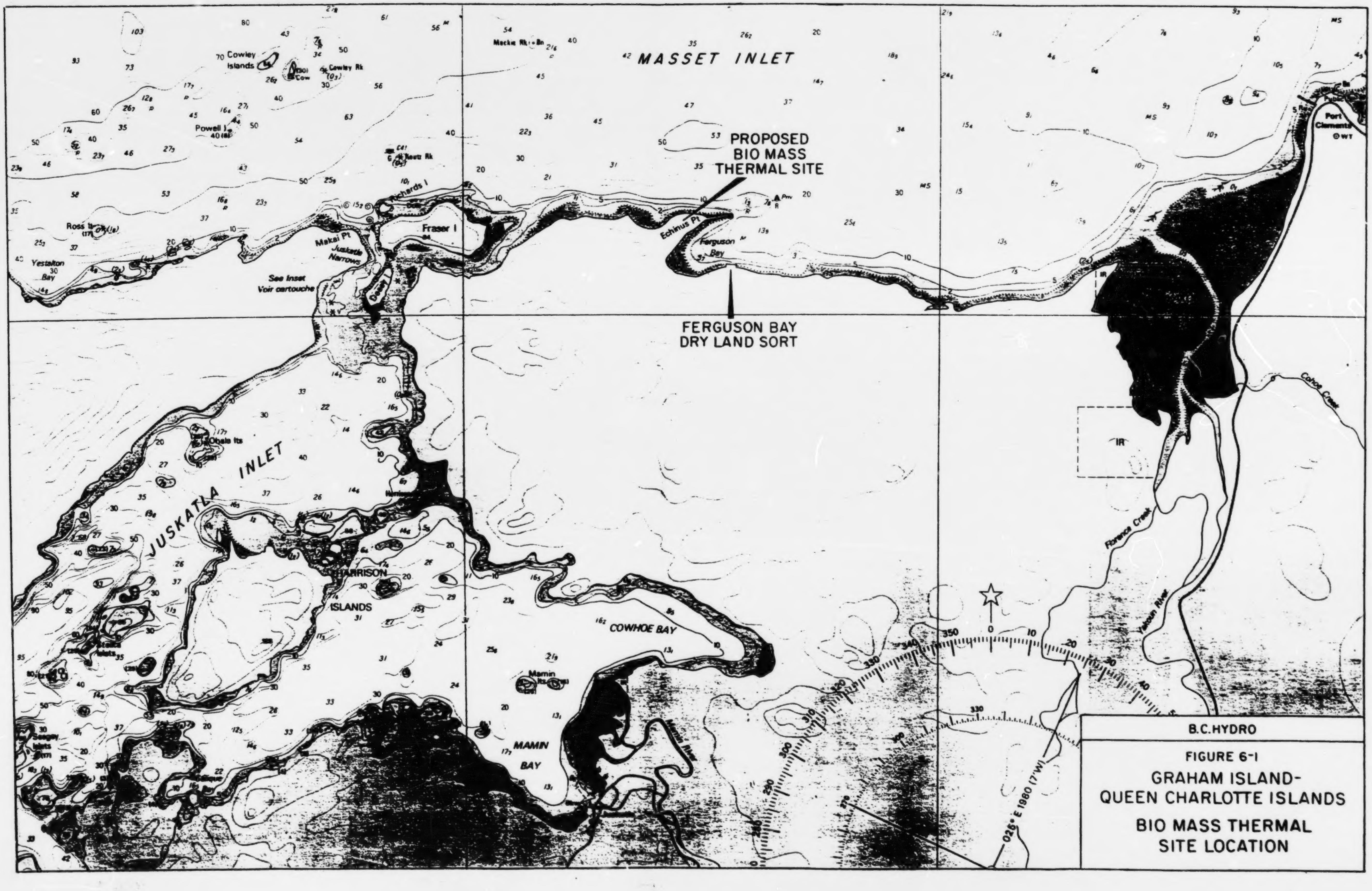
The Yakoun River system which flows into Masset Inlet 5 km to the east of the proposed site is the largest watershed of the Queen Charlotte Islands and is the main spawning area for the Masset Inlet pink salmon run, accounting for at least half of the total Queen Charlotte Islands pink salmon production. Numerous other streams on Graham Island are also used by spawning salmon.

Fresh water in the area of Ferguson Bay is presently obtained from wells at the dry land sort.

(b) Terrestrial Environment

The site is presently overgrown with second growth timber. The predominant tree species include western hemlock, site spruce and western red cedar. There is little underbrush and the forest floor is covered with deadfalls and rotting vegetation.

The site is on crown land adjacent to areas which have been logged by MacMillan Bloedel. A network of logging roads in the area



B.C.HYDRO

FIGURE 6-1

GRAHAM ISLAND-
QUEEN CHARLOTTE ISLANDS

BIO MASS THERMAL
SITE LOCATION

connect the Ferguson Bay dry land sort with the logging areas. There is also a road from the dry land sort to a causeway protruding from Echinus Point near the proposed powerplant site.

Geological characteristics of the site include sedimentary rock consisting of marine stony clays, till, outwash sands and gravel. The plant site is relatively flat and slopes gently upward from a wide beach covered with cobble-sized rock (5 to 25 cm) (Fig. 3-2). The foreshore shelves steeply to water depths of over 50 m and the marine charts indicate a sand bottom in the area.

Information on wildlife species and distribution is largely based on that contained in MacMillan Bloedel's resource files. These data have basically been collected from incidental sightings. Coastal black-tailed deer are found throughout the area. Various locations in and around Juskatla Inlet are utilized by ducks and geese as stopovers during migration. These are located at Ferguson Bay, Cowhoe Bay and Mamin Bay. Nesting geese have been observed on Fraser and Deasy Islands. Trumpeter swans are known to frequent Mamin Bay and occasionally Bird Lake to the southwest of Juskatla. Peregrine falcons as well as glaucous-winged gulls have also been observed in Juskatla Inlet.

(d) Meteorology

The proposed site of the thermal generating station is flanked to the south and southwest within 2 km by hills in excess of 120 m. This topographical feature would be the only constraint to low level wind circulation at the site. From other directions there would be no impediment to local winds.

There are no wind data for the immediate area, however long-term records for Sandspit Airport and Dead Tree Point, both on Hecate Strait, show that southeast winds prevail in all seasons along the coast. Examination of the topography southeast of the proposed site shows that elevations are low and uniform such that the prevailing winds along the coast would penetrate to Masset Inlet. The attached Sandspit Airport wind display (Fig. 6-2) exhibits fairly high frequencies of southwest and west wind directions. This is the incursion of Pacific air through Skidegate Channel at this location and would not occur over Masset Inlet where winds from these directions would be more in line with the frequencies shown on the Dead Tree Point wind display (Fig. 6-3).

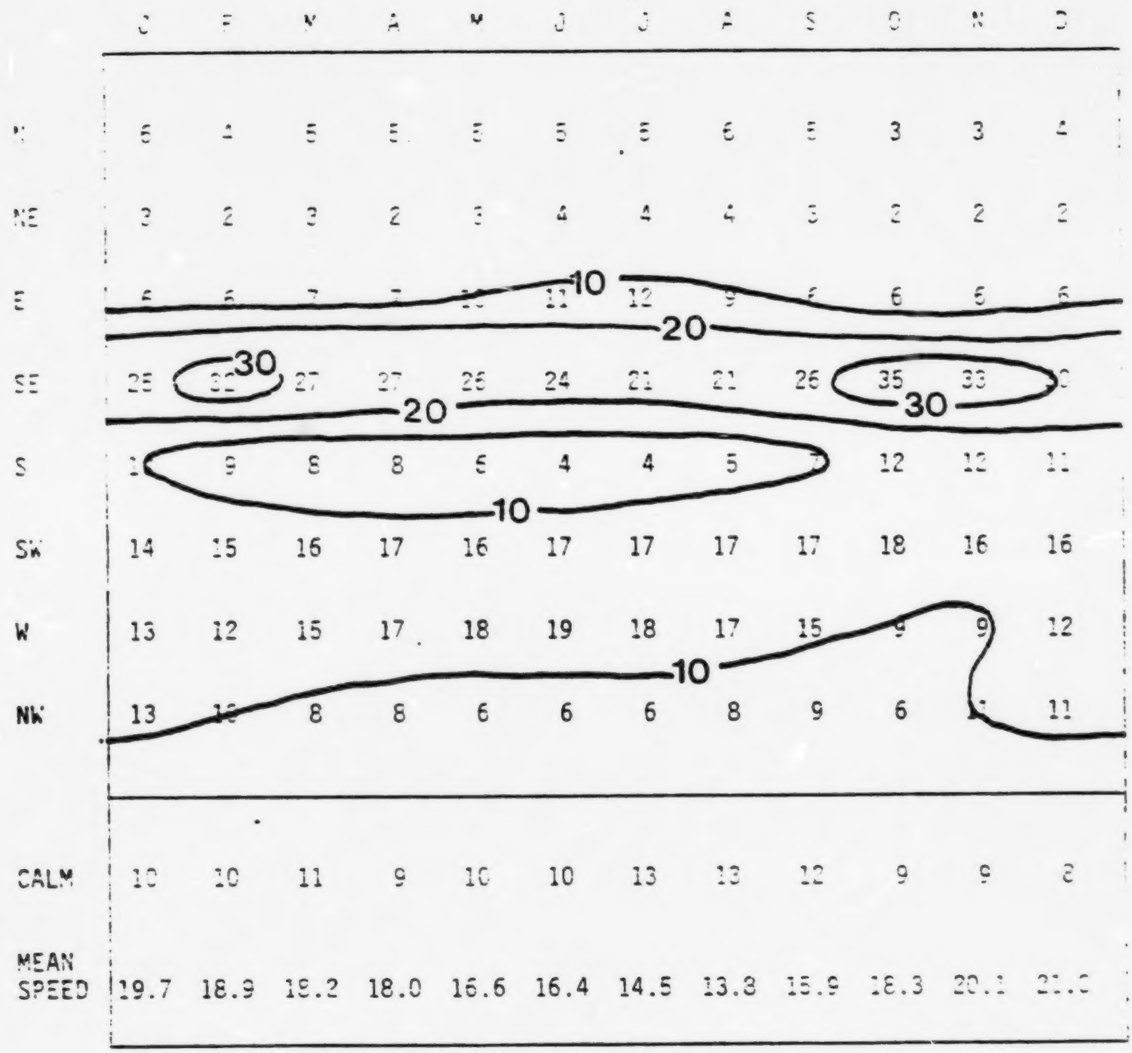
There are no ground-based inversion statistics for Masset Inlet, however examination of the climatological temperatures for Sewall (Table 6-1), on the north shore of the inlet, 10 km north of Echinus Point, can provide some insight into the probable seasonal and diurnal distribution of these. Normally, ground-based inversions have their highest frequency overnight and in the early morning in winter. From Table 6-1 Sewall has a mean minimum temperature from December to March near 0°C which is colder than the surface temperature of Masset Inlet. Hence, on Echinus Point, the air would be heated from below by the warmer surrounding water which would greatly reduce the formation of overnight inversions at this location. The reverse would be the case through the day in summer when the water surface would cool the lower air layers and promote inversion formation. However, examination of mean monthly wind speeds on Figs. 6-2 and 6-3 shows that these are fairly strong in all months and the resulting mechanical turbulence would inhibit inversion formation for much of the year.

Table 6-1 also shows that Sewall receives an average of 1343 mm of precipitation annually, with measurable precipitation on 60 percent of days. This would be similar to that received at Echinus Point.

TABLE 6-1

SEWALL TEMPERATURE AND PRECIPITATION DATA

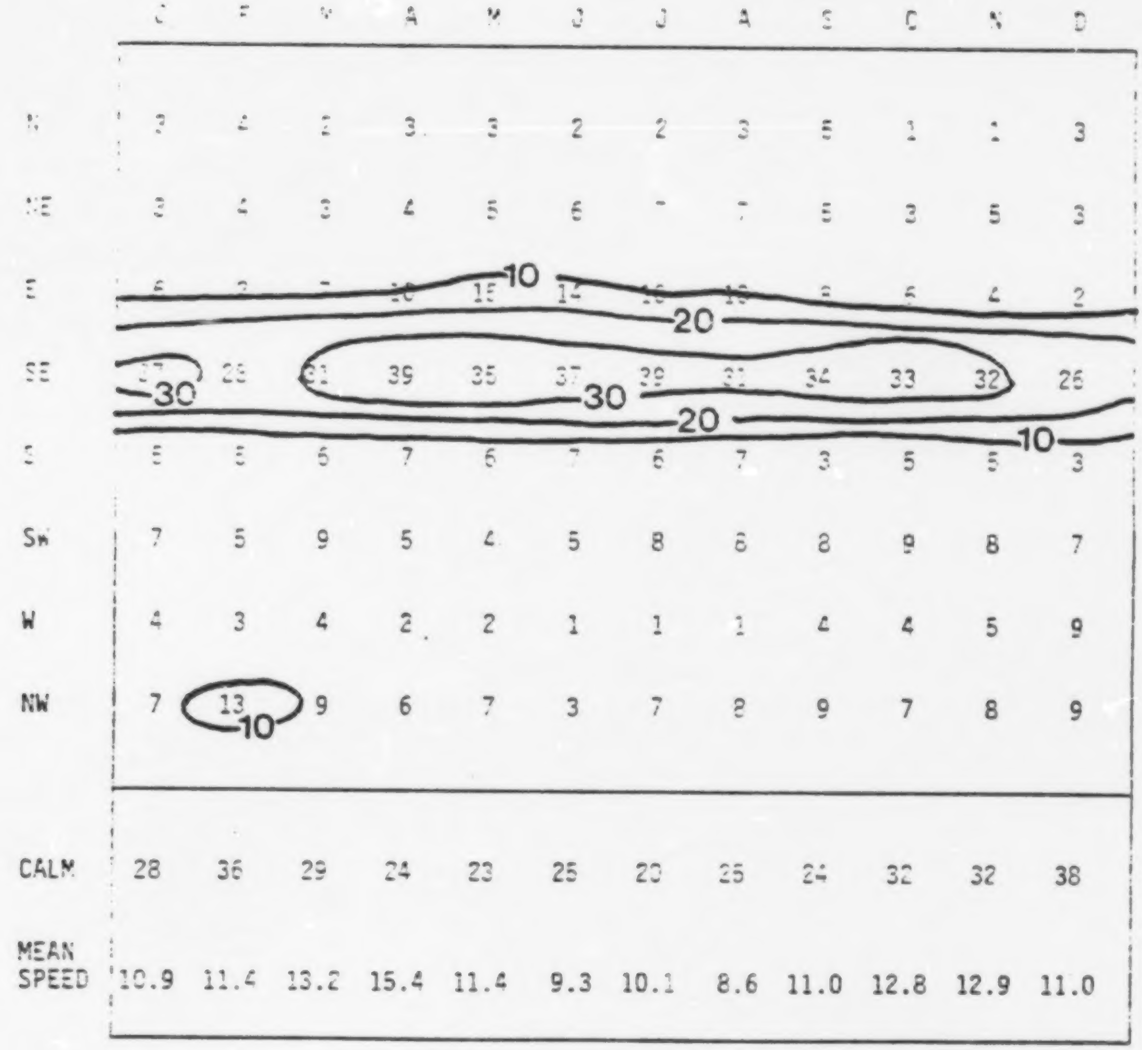
SEWALL MASSET INLET 53°46'N 132°18'W 3m	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
Daily Maximum Temperature (°C)	3.6	5.8	6.8	10.2	12.9	15.9	18.0	19.2	16.5	11.9	7.8	4.9	11.1 (ave)
Daily Minimum Temperature (°C)	-1.3	0.3	0.3	2.3	4.8	7.7	10.4	10.8	8.9	5.6	2.1	0.3	4.4 (ave)
Daily Temperature (°C)	1.2	3.0	3.6	6.2	8.8	11.8	14.3	14.8	12.5	8.8	5.0	2.6	7.7 (ave)
Standard Deviation, Daily Temperature (°C)	1.7	2.5	1.0	0.8	0.6	1.3	0.8	1.3	0.8	0.8	1.5	1.9	0.6
Extreme Maximum Temperature (°C)	11.7	12.2	15.6	21.1	21.7	26.5	28.9	32.2	26.1	18.0	14.0	11.5	32.2
Years of Record	6	6	6	6	6	6	7	7	7	7	7	7	
Extreme Minimum Temperature (°C)	-12.2	-11.1	-10.6	-2.2	-1.1	2.2	5.6	5.0	2.8	-1.7	-9.4	-13.3	-13.3
Years of Record	6	6	6	6	6	6	7	7	7	7	7	7	
Rainfall (mm)	101.3	72.6	83.6	78.1	56.4	58.5	53.2	52.2	111.8	219.1	169.3	149.4	1205.5
Snowfall (cm)	64.8	25.5	18.1	26.7	0.0	0.0	0.0	0.0	0.0	0.0	5.1	23.1	163.3
Total Precipitation (mm)	162.6	96.4	98.3	81.7	56.3	58.5	53.2	52.2	111.8	219.1	173.6	179.3	1343.0
Standard Deviation, Total Precipitation	81.1	28.6	29.9	35.7	26.9	41.5	33.4	25.5	33.6	90.0	49.7	51.3	91.2
Greatest Rainfall in 24 hours (mm)	32.3	30.2	22.1	30.2	14.7	25.9	21.3	25.9	51.3	62.7	46.5	39.9	62.7
Years of Record	6	6	6	6	6	6	7	7	7	7	7	7	
Greatest Snowfall in 24 hours (cm)	52.1	16.3	25.4	5.6	T	0.0	0.0	0.0	0.0	T	9.1	19.1	52.1
Years of Record	6	6	6	6	6	6	7	7	7	7	7	7	
Greatest Precipitation in 24 hours (mm)	52.1	30.2	25.4	30.2	14.7	25.9	21.3	25.9	51.3	62.7	46.5	39.9	62.7
Years of Record	6	6	6	6	6	6	7	7	7	7	7	7	
Days with Rain	15	15	19	16	15	13	13	13	16	25	22	20	202
Days with Snow	8	5	3	2	0	0	0	0	0	0	1	5	24
Days with Precipitation	20	18	21	17	15	13	13	13	16	25	23	24	218



	J	F	M	A	M	J	J	A	S	O	N	D
N	6	4	5	5	5	5	5	6	5	3	3	4
NE	3	2	3	2	3	4	4	4	3	2	2	2
E	6	6	7	7	10	11	12	9	6	6	5	6
SE	25	32	27	27	26	24	21	21	26	35	33	[illegible]
S	[illegible]	9	8	8	6	4	4	5	7	12	12	11
SW	14	15	16	17	16	17	17	17	17	18	16	16
W	13	12	15	17	18	19	18	17	15	9	9	12
NW	13	10	8	8	6	6	6	8	9	6	[illegible]	11
CALM	10	10	11	9	10	10	13	13	12	9	9	8
MEAN SPEED	19.7	18.9	18.2	18.0	16.6	16.4	14.5	13.8	15.9	18.3	20.1	21.0

SANDSPIT AIRPORT B.C. - PERCENTAGE FREQUENCY WIND DIRECTION (AND CALMS) AND MEAN WIND SPEED (KM/H) BY MONTHS (JANUARY 1955 TO DECEMBER 1980)

Figure 6.2
Sandspit Wind Data



	J	F	M	A	M	J	J	A	S	O	N	D
N	3	4	2	3	3	2	2	3	5	1	1	3
NE	3	4	3	4	5	6	7	7	5	3	5	3
E	6	2	7	10	15	14	10	10	8	6	4	2
SE	37	28	31	39	35	37	39	31	34	33	32	26
S	5	5	6	7	6	7	6	7	3	5	5	3
SW	7	5	9	5	4	5	8	8	8	9	8	7
W	4	3	4	2	2	1	1	1	4	4	5	9
NW	7	13	9	6	7	3	7	8	9	7	8	9
CALM	28	36	29	24	23	25	20	25	24	32	32	38
MEAN SPEED	10.9	11.4	13.2	15.4	11.4	9.3	10.1	8.6	11.0	12.8	12.9	11.0

DEAD TREE POINT B.C. - PERCENTAGE FREQUENCY WIND DIRECTION (AND CALMS) AND MEAN WIND SPEED (KM/H) BY MONTHS (FEBRUARY 1939 TO DECEMBER 1946)

Figure 6.3

Dead Tree Point Wind Data

6.4 IMPACT ASSESSMENT

(a) Socio-economic Effects

At the peak of the 2-year construction period the project is expected to employ about 160 people. Since most of the positions require highly technical skills, local employment would be limited to about 20 people. Local residents may obtain employment on the clearing contract for the transmission line and as labourers, carpenters and electricians in thermal plant construction. Spending by the work force on food and accomodations would inject an estimated $1.7 million dollars into the local economy, over the 2 years.

During operations about 30 people would be employed in the thermal plant and in providing the wood waste fuel. Most of the positions within the thermal plant would require specialized technical skills. With the reduction of manpower at the existing diesel stations at Sandspit and Masset, many of the thermal plant positions could be taken by existing B.C. Hydro employees, if additional steam operating training is obtained. The provision of the fuel supply would require skills which are similar to those which local residents currently possess. In total about 30 jobs may be obtained by local people with about two-thirds of these filled by transfers from the Hydro diesel stations on the Islands.

The extent to which the Port Clements population would increase would depend primarily on whether B.C. Hydro employees at Masset and Sandspit take new positions and move their families. While this is cannot be assessed at this stage, the newcomers could have significant effects on the provision of housing and social services.

The local population has expressed general support for the concept of biomass generation as a means to reduce diesel fuel consumption. The residents also perceive the project to be beneficial in that otherwise unused wood waste would be utilized.

Concern has been expressed about possible impacts of the project on air quality, the site selection process, employment opportunities during construction and operation, studies of other generation options, B.C. Hydro's commitment to alternative energy development, and local involvement in future studies. A comprehensive public information and consultation program would be essential to any further studies of the proposed plant. The project appears to have a potential for positive social and economic effects.

(b) Heritage Resources

Construction of the proposed thermal plant would not disturb any known archaeological sites. A detailed inventory of the site would be undertaken prior to any site disturbance and any necessary protective or recovery measures would also be taken. Impact of transmission line construction on unidentified heritage sites would be minimized by standard route selection and construction practices.

(c) Aquatic Effects

(i) Site Drainage

Surface water from rainfall on the 3 ha site would be directed off the site via drainage ditches. Uncontaminated water would be discharged directly to Masset Inlet. Any potentially contaminated runoff from the log storage and fuel handling areas would be mixed with cooling water before release to Masset Inlet. A dilution ratio in excess of 1000 to 1 is expected based on average flows.

(ii) Cooling Water

The once through cooling system would use a maximum of 0.5 m^3/s of sea water taken through a channelled intake from Masset Inlet. The water intake design would include a travelling water screen to prevent juvenile fish from being entrained in the inlet cooling water flow.

Cooling water would be returned to the inlet through a submerged diffuser at an estimated temperature of 21°C, which is 14°C above the inlet temperature. The exposed discharge location would be open to tidal flushing where water depths are in excess of 10 m. The mean tidal range at Port Clements is 2.2 m resulting in an estimated minimum water exchange rate within the initial dilution zone (100 m radius) of 20 percent approximately every 12 hours. Using a box model the temperature rise within the initial dilution zone would be less than 1°C under slack tide conditions. Tidal flushing would further dilute any weak thermal plume present.

Thermal plumes resulting from cooling water discharges can have a variety of potential effects. Fish are often attracted to the plume through thermoregulatory behaviour and the resulting temperature dependancy can be lethal if the high temperature environment is suddenly removed because of a plant shutdown or increased storm turbulence. However, since the cooling water discharge volume is small and the release would be through a submerged diffuser positioned away from the immediate shoreline there are not expected to be any measurable fisheries impacts. There could however be changes of some benthic invertebrates in the immediate vicinity of the discharge.

The waste heat contained in the cooling water may have some useful application for fisheries enhancement and or aquaculture.

(iii) Miscellaneous Effluents

Minor quantities of water from fresh water use would be discharged to the inlet after treatment to comply with Waste Management Branch objectives. These discharges would result from fresh water purification, boiler blowdown, building floor drains and log washing operations. A septic tank system would treat sewage requiring compliance with local standards and regulations.

(iv) Transmission Right-of-Way

Line construction would cause some short-term disturbance of wildlife but in the longer term the right-of-way would provide additional browse vegetation for deer. To minimize transmission construction impacts due to sedimentation on the fisheries resource, hand clearing would be required at stream crossings. The Yakoun River, Florence Creek, Kumdis Creek, Tlell River and Jungle Creek would be traversed by new or proposed upgraded transmission lines and are of particular value to the local fisheries resource.

(d) Terrestrial Effects

Project construction activities would have some minor impacts on the terrestrial environment. Construction noise would disturb deer, waterfowl and other birds in the immediate vicinity. Transmission line construction would require some additional clearing; however, all of the proposed line (new and upgrading) construction would be adjacent to existing roads.

Operation of the project would require the disposal of fly ash in a waste dump. No new impacts are expected since it is anticipated that the MacMillan Bloedel waste dump location would be available for ash disposal.

Fuel for the powerplant would be obtained from a mixture of sort-yard debris, logging wood waste and low grade pulp logs from the Juskatla Division of MacMillan Bloedel. A net benefit would occur since potential thermal plant fuel would no longer be land filled, and the reduced amounts of roadside logging debris would improve the aesthetics of logged areas.

(e) Air Quality Effects

(i) Powerplant Emissions

The major pollutant of concern from wood/bark boilers is particulate matter resulting from uncollected ash, although other pollutants, sulphur oxides, carbon monoxide, hydrocarbons and nitrogen oxides are also released. Contact was made with the Waste Management Branch who advised that the Provincial Pollution Control emission objectives for wood-fired power boilers in the Forest Products Industry would likely be used. These objectives specify level A emissions for particulates of 5.5 mg/mol (0.10 gr/sdcf) and stack gas opacity of 20 percent. Particulate removal devices would be designed to remove fly ash from the boiler flue gases to this level.

Emission factors for boiler combustion and open burning of wood waste are shown in Table 6-2. Open burning is presently used to dispose of all the debris (3825 t/a) from the Ferguson Bay land sort resulting in approximately 33 t/a of particulate emissions. The proposed 10 MW boiler burning 49 000 t/a of

TABLE 6-2

EMISSIONS OF AIR CONTAMINANTS

Contaminant	Opening Burning[*1]		Wood Waste Boiler[*2]	
	Emission Factor (Kg/t)	Dry Land Sort Emissions (t/a)	Emission Factor (Kg/t)	Projected Emissions (t/a)
Particulates	8.5	33	0.1	5
Sulphur Dioxide	0.75	3	0.75	35
Carbon Monoxide	25.0	96	1.0	47
Hydrocarbons	2.0	8	1.0	47
Nitrogen Oxides	1.0	4	0.8	38

Notes:

[*1] 3825 t/a of wood waste are burned at the dry land sort.

[*2] The 10 MW powerplant will require 49 000 t of wood waste per year. Particulate removal efficiency - 99.3 percent.

[*3] Information Sources:

- Compilation of Air Pollution Factors, U.S. EPA, AP-42, March 1975.
- NO_x Emission Factors for Wood-Fired Boilers, EPA 600/7-79-219, September 1979.

wood waste would generate 5 t/a of particulate emissions. It is expected that the powerplant's requirement for wood debris would considerably reduce the amount of material disposed of by open burning and thereby actually reduce particulate emissions in the area.

The only gaseous contaminant dealt with in the objectives is sulphur dioxide, which is regulated on a site specific basis depending on the fuel used. The fuel being considered for power generation at Ferguson Bay is wood waste which has a maximum sulphur content of 0.1 percent. If an auxiliary fuel with a different sulphur content is considered in a later study phase a further assessment would be required.

Table 6-2 also describes the gaseous emissions of carbon monoxide, hydrocarbons, and nitrogen oxides released during the combustion of wood debris. From the comparison of the two firing methods it is evident that a wood waste boiler would generally produce lower specific emissions of these contaminants. However total emissions of sulphur dioxide hydrocarbons and nitrogen oxides would be higher due to the larger quantity of wood waste burned. Exhaust gas from the boilers would be dispersed from an elevated stack as compared to open burning releases which undergo limited dilution before impacting nearby receptors. While wood waste combustion in the Port Clements area would increase there would be a corresponding decrease in emissions from the existing diesel generating stations at Sandspit and Masset.

(ii) Ambient Air Quality

Airborne emissions from the proposed biomass thermal plant on Echinus Point would be affected by the meteorological parameters described in Section 6.3(d). With moderately high wind

TABLE 6-3

AMBIENT AIR QUALITY OBJECTIVES - FOREST PRODUCTS INDUSTRY

Parameter	Period Over Which Analysis Is Averaged	Units	Level A	Level B
Sulphur dioxide	1 hour	μg/m³	450	900
	24 hours	μg/m³	160	260
	1 year	μg/m³	25	50
Total reduced sulphur (TRS) compounds measured as H_2S	1 hour	μg/m³	7	28
	24 hours	μg/m³	3	6
Total suspended particulate matter	24 hours	μg/m³	150	200
	1 year (geometric mean)	μg/m³	60	70
Total dustfall	2 weeks	mg/(dm².d)		
Residential			1.75	1.75
Other			2.90	2.90
Chlorine and chlorine dioxide	24 hours	μg/m³	150	300

speeds in all months of the year, horizontal dispersion of the emissions would be good. Turbulence resulting from these winds, and the warming of the air mass by the inlet waters in winter, would impede the formation of inversions so that vertical dispersion of the emissions should also be fairly good.

With high monthly and annual precipitation, and measurable precipitation on 60 percent of days, rainout and washout of airborne emissions should be quite effective.

The boiler stack would be designed with sufficient height to disperse emissions so that ground level concentrations would be within ambient air quality objectives (Table 6-3).

6.5 FURTHER STUDIES

The studies listed below would be conducted as part of more detailed feasibility investigations of a wood waste thermal generating facility near Ferguson Bay should the development plan proceed further.

(a) Socio-economic

Further socio-economic studies should provide information on employment skills of local residents to assess the number of local people who may obtain jobs and the number of people who will move to the area. From this inventory the effects on the local economy, housing, social services and social structure can be assessed. The need for any mitigation or compensation is unlikely but should be verified. Other inventory work would include documentation of current and proposed land use and information on hunting efforts and harvest in the general area.

(b) Heritage Resources

A survey of areas to be disturbed during construction should be conducted to document heritage sites that may be affected.

(c) Aquatic Resources

An inventory of marine and shoreline biota in the vicinity of Ferguson Bay and Echinus Point would be required for an impact assessment of the cooling water intake and to optimize outlet design. Transmission right-of-way crossings of sensitive salmon spawning streams would also be identified.

All liquid effluents would be assessed with respect to the quantity and quality of the discharge and comparisons made with accepted practice and government objectives.

(d) Terrestrial Environment

Wildlife studies would comprise an inventory of the abundance and distribution of deer habitat in areas which would be affected by powerplant and transmission line construction. Waterfowl stopover, nesting and staging areas in Ferguson Bay should be surveyed. Vegetation types and sensitivities to disturbance in the vicinity of the proposed powerplant and on proposed transmission right-of-ways would be identified. An assessment of the proposed fly ash disposal location and disposal method is necessary.

(e) Air Quality

The next major step in the assessment of air quality would be the documentation of existing air quality and the identification of existing sources which contribute to background levels. The assessment would define the future powerplant's emissions and a computer simulation would be used to predict dispersion of these emissions to ground level.

SECTION 7.0 - ECONOMIC EVALUATION

7.1 ECONOMIC PARAMETERS

A computer program has been developed by the System Studies Section of the Generation Planning Department of B.C. Hydro. This program was used to compare unit energy cost estimates for the wood-fired thermal generating station with wood gasification power generation and the present diesel generating system. The unit energy cost is used in this report to examine the relative cost of thermal generation in 1994/95 in June 1984 Canadian dollars. For reference, the break even cost of wood fuel, for thermal generation was determined for a unit energy cost equal to the present cost of diesel generated power.

Plant costs have been estimated based on quotations from particular equipment suppliers who appear to have sufficiently commercialized and demonstrated power generating packages available. Thus, many of the questions of technical feasibility have been answered. In a more detailed investigation, several alternative wood-fired thermal generating schemes would be evaluated.

Construction costs for plants, substations and transmission lines were estimated for each of the two thermal generation options. These estimates assumed that the Ferguson Bay site would be available and that no extraordinary amount of site preparation would be required. Transmission and substation cost estimates include surveys, clearing (20 m wide), materials labour, and right-of-way acquisition. A considerable cost is included in this study to connect the two existing diesel generating station distribution systems with a transmission line. For the Project Evaluation, the transmission line tie-in between the plant and the Port Clements substation is included in the plant construction cost and would be typical of any generating station tie-in. The extra transmission and substation work to connect the Masset and Sandspit generating systems can be either included or excluded for the Queen Charlotte Islands evaluation.

The project cost ($/kW) is the ratio of the sum of the costs of construction, engineering and contingencies (including corporate overhead and interest during construction) to the plant capacity. For this study, corporate overhead for B.C. Hydro is estimated to be 9 percent of the project cost for substations and transmission lines (because of the in-house design) and 2 1/2 percent of the plant cost in which the design costs are included in the plant cost estimates. Due to the preliminary nature of this study, contingencies were applied at 20 percent.

Operating and maintenance costs have been estimated for the 10 MW thermal generating station based on manufacturers information and the minimum plant staff requirements anticipated. Although steam plant operators are not required for the gasification plant, the larger number of smaller units, and the less proven technology will require higher maintenance costs, thus the operating and maintenance requirements for both plants were assumed to be the same at $1.79 million per year. Transmission line and substation maintenance was assumed to be $0.146 million per year for both plants.

Fuel costs and availability for both plants are essentially the same based on information derived from the Forest Engineering Research Institute of Canada, the B.C. Forest Service and MacMillan Bloedel. Of the scenarios provided in Section 2.0, Scenario III which includes wood fuel supplied first by wood residues accumulated at the Ferguson Bay landsort (3825 ODt/a), second by wood waste generated at the landings during logging (12 750 ODt/a), third by logging residues left in the bush (19 200 ODt/a), and finally by low grade pulp logs (up to 14 225 ODt/a), was assumed to be the most reasonable. The cost of the raw wood fuel delivered to the plant site was thus assumed, for the base case, to be $100.40/ODt.

In response to personal communication with MacMillan Bloedel,[20] a Scenario IV was recommended to be included which does not include use of any pulp logs. Under this scenario wood fuel would cost $153.46/ODt. MacMillan Bloedel indicated that if available the cost of pulp logs for fuel would be $101.75/ODt, making the average blended wood fuel cost about $80/ODt. Further discussions with MacMillan Bloedel indicated that 33,000 ODT/a of low grade pulp wood could be made available at a delivered cost in the order of $100/ODt.[22] To show the sensitivity of the unit energy cost to fuel cost, fuel costs at $31.10/ODt and $153.46/ODt were tested. The wood fuel costs do not include plant related fuel preparation, chipping, storage or dumping costs. These items are part of the estimated plant costs.

The energy costs of the thermal generating station options were compared with the actual cost of diesel generation at a fuel cost of 35.1¢/L (average cost of diesel fuel on the Queen Charlotte Islands in June 1984). The average annual operating cost was determined both with no capital recovery (assuming the diesel plants are already written off) and including a capital recovery allowance. For equivalent comparison, the cost of energy in 1994/95 was determined assuming the real cost of diesel fuel increased at an average rate of 1 percent per year (net of inflation) to 38.6¢/L. Diesel fuel costs include the cost of lube oil and all taxes and delivery charges.

Energy costs are estimated at the following discount rates (net of inflation) 4, 6, and 8 percent. B.C. Hydro is presently using a 4 percent net discount rate. Interest during construction (IDC) is calculated on the project cost including engineering, contingencies, and corporate overhead. The IDC cost is based on the estimated construction schedules for each plant.

7.2 ENERGY COSTS

A computer program developed for comparing energy costs of generation projects was used to evaluate the two wood-fired thermal power generation options (wood-fired steam plant and wood gasification) and to compare them with the existing diesel generating system. The base case alternatives were compared at 4, 6 and 8 percent discount rates. The resulting energy costs are summarized in Table 7-1.

The sensitivity of increasing diesel fuel costs by 1 percent per annum (net of inflation) over the 10-year period, to 38.6¢/L, results in an effective 10 mills/kW·h increase in the unit energy cost of diesel generation. The sensitivity of wood fuel cost on thermal power generation is shown to result in unit energy costs of 112 mills/kW·h and 245 mills/kW·h (excluding transmission) for wood fuel at $31.10/ODt and $153.46/ODt, respectively. Unit energy costs have been compared to the 1994/95 cost of diesel generation at 165 mills/kW·h (in June 1984 Canadian dollars) to determine the break even wood fuel supply cost of $61.33/ODt, at a 4 percent net discount rate.

Discussions with MacMillan Bloedel, regarding the supply of wood fuel to a plant at Ferguson Bay, indicates that although there is a surplus of wood waste available in the Juskatla and Skidegate areas now because of the depressed pulp markets, this may not always be the case. Thus commitment of the pulp wood to a thermal generating station at a cost of $23.50 or $36.50/ODt as indicated by FERIC is not a reasonable assumption.

Although it is not possible at this time, at this prefeasibility level of study, to obtain a firm price and a firm commitment from MacMillan Bloedel for the supply of wood fuel to a thermal generating station, it has been indicated that up to 33,425/ODt of low grade pulp logs at $100/ODt might be available resulting in a weighted average cost of $80/ODt. With a maximum (20 percent of capital cost) grant from the

TABLE 7-1

QUEEN CHARLOTTE ISLANDS - BIOMASS UTILIZATION STUDY
PROJECT EVALUATION SUMMARY
(Costs in June 1984 Canadian Dollars)

Generating System	Peak Capacity (MW)	Annual Energy Demand 1994/95	Fuel Cost	Notes	Unit Energy Cost 4% Net Discount Rate (mills/kW-h)	 6% Net Discount Rate (mills/kW-h)	 8% Net Discount Rate (mills/kW-h)
Present Diesel Generation	16.8	37.50	$8.96/GJ (35.14/L)	Average annual operating cost, June 1984 (no capital recovery allowance)	134		
	16.8	45.54	$8.96/GJ	Average annual operating cost, June 1984 (including capital recovery)	155	159	164
	16.8	45.54	$9.85/GJ (38.66/L)	"Base Case" (fuel cost inflated at 1% per year net of inflation to 1994/95)	165	169	174
Wood-Fired Thermal Generation	10.00	45.54	$31.10/ODt	Scenario II fuel cost - with transmission	132	146	164
				Scenario II fuel cost - without transmission	112	123	134
			$153.46/ODt	Scenario IV fuel cost - with transmission	264	278	293
				Scenario IV fuel cost - without transmission	245	255	266
			$100.40/ODt	"Base Case" Scenario III fuel cost - with transmission	207	221	236
				Scenario III fuel cost - without transmission	187	197	209
			$61.33/ODt	Break-even fuel cost - with transmission	165		
			$52.77/ODt	Break-even fuel cost - with transmission		169	
			$43.36/ODt	Break-even fuel cost - with transmission			174
			$67.41/ODt	Break-even fuel cost - with transmission (with maximum 20% FIRE GRANT)	165		
Wood Gasification Power Generation	10.28	45.54	$31.10/ODt	Scenario II fuel cost - with transmission	139	155	173
				Scenario II fuel cost - without transmission	119	132	146
			$153.46/ODt	Scenario IV fuel cost - with transmission	262	278	295
				Scenario IV fuel cost - without transmission	242	254	268
			$100.40/ODt	"Base Case" Scenario III fuel cost - with transmission	208	225	242
				Scenario III fuel cost - without transmission	189	201	215
			$56.82/ODt	Break-even fuel cost - with transmission	165		
			$45.35/ODt	Break-even fuel cost - with transmission		169	
			$32.09/ODt	Break-even fuel cost - with transmission			174

Forest Industry Renewable Energy (FIRE) Program for plant construction, the break even price for wood fuel could be $67.41/ODt. With some further financial support by an interested participant and a lower cost for the wood fuel, the 10 MW thermal generating station could be justified.

The back-up information and Project Evaluation (PROJEVAL) computer print-out sheets supporting the data contained in Table 7-1 is provided in Appendix A.

SECTION 8.0 - CONCLUSIONS AND RECOMMENDATIONS

The results of this Biomass Utilization Study for the Queen Charlotte Islands indicates that sufficient wood waste in the form of logging and land sort residues is available in the vicinity of Ferguson Bay to fuel a 10 MW wood-fired thermal generating station if low grade pulp logs or high cost logging residues left in the bush are used. If low grade pulp logs were available they could provide the more economic fuel supply base.

MacMillan Bloedel have indicated that the present surplus of pulp logs is temporary and the present low cost of pulp logs for fuel described under fuel supply Scenario II (at $31.10/ODt) cannot be relied upon. MacMillan Bloedel have also indicated that a long-term supply of wood under fuel supply Scenario IV might cost up to $153.46/ODt. Low grade pulp logs could be made available at a delivered cost in the order of $100/ODt. Use of 33,425/ODt of low grade pulp logs would result in an average blended wood fuel cost of about $80/ODt. The break even cost compared to the present diesel generation of a wood fuel supply for wood-fired thermal generation and wood gasification power generation (as shown in Table 7-1) would be $61.33/ODt and $56.82/ODt, respectively. The effect of a 20 percent grant, (based on plant capital cost) for plant construction, under the FIRE program would be to increase the break even fuel cost for the thermal plant to $67.41/ODt. With further financial support by an interested participant willing and able to design, construct and operate the 10 MW wood-fired thermal generating station, and a firm committment by MacMillan Bloedel to supply the wood fuel, the thermal generating station could be economically feasible. If the perceived cost of diesel fuel was seen to increase at greater than 1 percent per year (net of inflation) the economics of using biomass for power generation would improve.

There is not a significant difference in unit energy costs indicated for wood-fired thermal generation over wood gasification power generation at this time. The conventional thermal generating technology and cost information, however, is much more advanced and would be much more reliable. As the wood gasification power generating technology is improved and demonstrated the costs and reliability may improve to the point where it could be quite competitive to conventional wood-fired thermal generation.

At this prefeasibility level of investigation it has been found that:

1. There is sufficient wood waste available in the form of logging residues from the MacMillan Bloedel operations in the Ferguson Bay area to fuel a 10 MW thermal generating station.

2. The cost of the wood waste (including some low grade pulp logs) appears to be within a negotiable range of the break even cost of wood fuel necessary to compete with the present diesel generating systems.

3. A conventional thermal generating station would be more reliable than wood gasification power generation in the near term.

4. A third party has indicated an interest in participating in a feasibility study and detailed station design, and would be willing and able to construct and operate the generating station if it was found to be economically viable.

5. No major environmental constraints were identified and some environmental and socio-economic benefits may result from the construction and operation of the station.

Based on the results obtained from this prefeasibility evaluation of the utilization of biomass for power generation on the Queen Charlotte Islands, is recommended that:

1. a detailed station design and feasibility study be carried out for the siting of a centrally located 10 MW conventional wood-fired thermal generating station on the Queen Charlotte Islands;
2. a consultant capable of designing, constructing and operating the thermal generating station be solicited and participate in the design study; and
3. funding be considered under the Phase II, Enerdemo - Canada, Program.

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21. Personal Communiation, Meeting between Dr. Charles Tarnocai, Ministry of Agriculture, Canada and L. Roosdahl, 26 September 1984. Data being assembled for a general Canadian peat inventory report to be issued in 1985.

APPENDIX A

PROJECT EVALUATION DATA SHEETS

APPENDIX A

PROJECT EVALUATION DATA SHEETS

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TABLE A-1

Project Evaluation Package AUG 29 1984

Project Data For: GCI DGS

Project Capability		
Peak Capacity	(MW)	16.80
Firm Energy	(GW.h)	45.54
Secondary Energy	(GW.h)	.00

Unit Fuel Cost	($/GJ) ==>	8.96
	($/tonne) ==>	.00
Calorific Value	(MJ/Kg) ==>	.00
Heat Rate	(GJ/GWh) ==>	11393.00
Efficiency	(%) ==>	.00
Fuel Cost	(mills/kW.h) ==>	102.08
Fuel Consumption	(kt/a) ==>	.00

FUEL COST
(35.1¢/L)

4%
NET
DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	14569	0	0	14569
Contingency Allowance	0	0	0	0
Overhead Allowance	0	0	0	0
Interest During Const.	0	0	0	0
Total Capital Cost	14569	0	0	14569
Cost per KiloWatt ($/KW)	867	0	0	867

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	1072	0	0	1072
Operation & Maintenance	1155	0	0	1155
School Taxes	172	0	0	172
Fuel Costs	4649	0	0	4649
Total Annual Cost	7048	0	0	7048
Cost per KW.h (mills/kW.h)	154.76	.00	.00	154.76

6%
NET
DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	14569	0	0	14569
Contingency Allowance	0	0	0	0
Overhead Allowance	0	0	0	0
Interest During Const.	0	0	0	0
Total Capital Cost	14569	0	0	14569
Cost per KiloWatt ($/KW)	867	0	0	867

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	1270	0	0	1270
Operation & Maintenance	1155	0	0	1155
School Taxes	172	0	0	172
Fuel Costs	4649	0	0	4649
Total Annual Cost	7246	0	0	7246
Cost per KW.h (mills/kW.h)	159.11	.00	.00	159.11

8%
NET
DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	14569	0	0	14569
Contingency Allowance	0	0	0	0
Overhead Allowance	0	0	0	0
Interest During Const.	0	0	0	0
Total Capital Cost	14569	0	0	14569
Cost per KiloWatt ($/KW)	867	0	0	867

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	1484	0	0	1484
Operation & Maintenance	1155	0	0	1155
School Taxes	172	0	0	172
Fuel Costs	4649	0	0	4649
Total Annual Cost	7460	0	0	7460
Cost per KW.h (mills/kW.h)	163.81	.00	.00	163.81

TABLE A-2

Project Evaluation Package SEP 14 1984

Project Data For: GCI DGS

Project Capability		
Peak Capacity	(MW)	16.80
Firm Energy	(GW.h)	45.54
Secondary Energy	(GW.h)	.00

Unit Fuel Cost	($/GJ) ==>	9.85
	($/tonne) ==>	.00
Calorific Value	(MJ/Kg) ==>	.00
Heat Rate	(GJ/GWh) ==>	11393.00
Efficiency	(%) ==>	.00
Fuel Cost	(mills/kW.h) ==>	112.22
Fuel Consumption	(kt/a) ==>	.00

Base Case
ASSUMED 1994/95
FUEL COST
(38.6¢/L)

4% NET DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	14569	0	0	14569
Contingency Allowance	0	0	0	0
Overhead Allowance	0	0	0	0
Interest During Const.	0	0	0	0
Total Capital Cost	14569	0	0	14569
Cost per KiloWatt ($/KW)	867	0	0	867

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	1072	0	0	1072
Operation & Maintenance	1155	0	0	1155
School Taxes	172	0	0	172
Fuel Costs	5111	0	0	5111
Total Annual Cost	7510	0	0	7510
Cost per KW.h (mills/kW.h)	164.90	.00	.00	164.90

6% NET DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	14569	0	0	14569
Contingency Allowance	0	0	0	0
Overhead Allowance	0	0	0	0
Interest During Const.	0	0	0	0
Total Capital Cost	14569	0	0	14569
Cost per KiloWatt ($/KW)	867	0	0	867

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	1270	0	0	1270
Operation & Maintenance	1155	0	0	1155
School Taxes	172	0	0	172
Fuel Costs	5111	0	0	5111
Total Annual Cost	7708	0	0	7708
Cost per KW.h (mills/kW.h)	169.25	.00	.00	169.25

8% NET DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	14569	0	0	14569
Contingency Allowance	0	0	0	0
Overhead Allowance	0	0	0	0
Interest During Const.	0	0	0	0
Total Capital Cost	14569	0	0	14569
Cost per KiloWatt ($/KW)	867	0	0	867

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	1484	0	0	1484
Operation & Maintenance	1155	0	0	1155
School Taxes	172	0	0	172
Fuel Costs	5111	0	0	5111
Total Annual Cost	7922	0	0	7922
Cost per KW.h (mills/kW.h)	173.95	.00	.00	173.95

TABLE A-3

Project Evaluation Package SEP 20 1984

Project Data For: QCI BIOMASS THERMAL

Project Capability		
Peak Capacity	(MW)	10.00
Firm Energy	(GW.h)	45.54
Secondary Energy	(GW.h)	.00
Unit Fuel Cost	($/GJ) ==>	.00
	($/tonne) ==>	31.10
Calorific Value	(MJ/Kg) ==>	20.00
Heat Rate	(GJ/GWh) ==>	21600.00
Efficiency	(%) ==>	.00
Fuel Cost	(mills/kW.h) ==>	33.59
Fuel Consumption	(kt/a) ==>	49.18

Scenario II
Fuel Cost

4% NET DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	22892	5888	2630	31410
Contingency Allowance	4418	589	263	5270
Overhead Allowance	683	583	260	1526
Interest During Const.	624	56	53	734
Total Capital Cost	28617	7116	3206	38940
Cost per KiloWatt ($/KW)	2862	712	321	3894

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	1533	412	185	2130
Operation & Maintenance	1790	123	23	1936
School Taxes	268	110	49	427
Fuel Costs	1530	0	0	1530
Total Annual Cost	5120	645	258	6023
Cost per KW.h (mills/kW.h)	112.43	14.16	5.66	132.25

6% NET DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	22892	5888	2630	31410
Contingency Allowance	4418	589	263	5270
Overhead Allowance	683	583	260	1526
Interest During Const.	938	85	79	1103
Total Capital Cost	28931	7144	3233	39309
Cost per KiloWatt ($/KW)	2893	714	323	3931

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	1996	519	235	2749
Operation & Maintenance	1790	123	23	1936
School Taxes	268	110	49	427
Fuel Costs	1530	0	0	1530
Total Annual Cost	5582	752	307	6642
Cost per KW.h (mills/kW.h)	122.58	16.52	6.75	145.85

8% NET DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	22892	5888	2630	31410
Contingency Allowance	4418	589	263	5270
Overhead Allowance	683	583	260	1526
Interest During Const.	1254	113	106	1473
Total Capital Cost	29247	7173	3259	39679
Cost per KiloWatt ($/KW)	2925	717	326	3968

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	2509	637	290	3436
Operation & Maintenance	1790	123	23	1936
School Taxes	268	110	49	427
Fuel Costs	1530	0	0	1530
Total Annual Cost	6096	870	362	7329
Cost per KW.h (mills/kW.h)	133.87	19.11	7.95	160.93

TABLE A-4

```
                    Project Evaluation Package              SEP 20 1984

 Project Data For:        QCI BIOMASS THERMAL

 Project Capability
    Peak Capacity        (MW)           10.00
    Firm Energy        (GW.h)           45.54
    Secondary Energy   (GW.h)             .00

Unit Fuel Cost    ($/GJ) ==>              .00
              ($/tonne) ==>            153.46
Calorific Value (MJ/Kg) ==>             20.00

Heat Rate       (GJ/GWh) ==>         21600.00
Efficiency           (%) ==>              .00

Fuel Cost  (mills/kW.h) ==>            165.74
Fuel Consumption (kt/a) ==>             49.18
```

Scenario IV
Fuel Cost

4%
NET
DISCOUNT RATE

```
Capital Cost Summary (K$)                  Gener.    Trans.    Subst.    Total
   Construction Cost                        22892      5888      2630    31410
   Contingency Allowance                     4418       589       263     5270
   Overhead Allowance                         683       583       260     1526
   Interest During Const.                     624        56        53      734
   Total Capital Cost                       28617      7116      3206    38940
   Cost per KiloWatt ($/KW)                  2862       712       321     3894

Annual Cost Summary (K$)                   Gener.    Trans.    Subst.    Total
   Capital Recovery                          1533       412       185     2130
   Operation & Maintenance                   1790       123        23     1936
   School Taxes                               268       110        49      427
   Fuel Costs                                7548         0         0     7548
   Total Annual Cost                        11138       645       258    12041
   Cost per KW.h (mills/kW.h)              244.58     14.16      5.66   264.40
```

6%
NET
DISCOUNT RATE

```
Capital Cost Summary (K$)                  Gener.    Trans.    Subst.    Total
   Construction Cost                        22892      5888      2630    31410
   Contingency Allowance                     4418       589       263     5270
   Overhead Allowance                         683       583       260     1526
   Interest During Const.                     938        85        79     1103
   Total Capital Cost                       28931      7144      3233    39309
   Cost per KiloWatt ($/KW)                  2893       714       323     3931

Annual Cost Summary (K$)                   Gener.    Trans.    Subst.    Total
   Capital Recovery                          1996       519       235     2749
   Operation & Maintenance                   1790       123        23     1936
   School Taxes                               268       110        49      427
   Fuel Costs                                7548         0         0     7548
   Total Annual Cost                        11601       752       307    12660
   Cost per KW.h (mills/kW.h)              254.73     16.52      6.75   278.00
```

8%
NET
DISCOUNT RATE

```
Capital Cost Summary (K$)                  Gener.    Trans.    Subst.    Total
   Construction Cost                        22892      5888      2630    31410
   Contingency Allowance                     4418       589       263     5270
   Overhead Allowance                         683       583       260     1526
   Interest During Const.                    1254       113       106     1473
   Total Capital Cost                       29247      7173      3259    39679
   Cost per KiloWatt ($/KW)                  2925       717       326     3968

Annual Cost Summary (K$)                   Gener.    Trans.    Subst.    Total
   Capital Recovery                          2509       637       290     3436
   Operation & Maintenance                   1790       123        23     1936
   School Taxes                               268       110        49      427
   Fuel Costs                                7548         0         0     7548
   Total Annual Cost                        12115       870       362    13347
   Cost per KW.h (mills/kW.h)              266.02     19.11      7.95   293.08
```

TABLE A-5

```
                     Project Evaluation Package            SEP 20 1984

   Project Data For:        QCI BIOMASS THERMAL

   Project Capability
      Peak Capacity       (MW)          10.00
      Firm Energy        (GW.h)         45.54
      Secondary Energy   (GW.h)           .00
  Unit Fuel Cost    ($/GJ) ==>            .00
                ($/tonne) ==>          100.40
  Calorific Value (MJ/Kg) ==>           20.00

  Heat Rate       (GJ/GWh) ==>       21600.00
  Efficiency           (%) ==>            .00

  Fuel Cost  (mills/kW.h) ==>          108.43
  Fuel Consumption (kt/a) ==>           49.18
```

Base Case
Scenario III
Fuel Cost

4%
NET
DISCOUNT RATE

```
Capital Cost Summary (K$)              Gener.   Trans.   Subst.    Total
   Construction Cost                    22892     5888     2630    31410
   Contingency Allowance                 4418      589      263     5270
   Overhead Allowance                     683      583      260     1526
   Interest During Const.                 624       56       53      734
   Total Capital Cost                   28617     7116     3206    38940
   Cost per KiloWatt ($/KW)              2862      712      321     3894

Annual Cost Summary (K$)               Gener.   Trans.   Subst.    Total
   Capital Recovery                      1533      412      185     2130
   Operation & Maintenance               1790      123       23     1936
   School Taxes                           268      110       49      427
   Fuel Costs                            4938        0        0     4938
   Total Annual Cost                     8529      645      258     9431
   Cost per KW.h (mills/kW.h)          187.28    14.16     5.66   207.09
```

6%
NET
DISCOUNT RATE

```
Capital Cost Summary (K$)              Gener.   Trans.   Subst.    Total
   Construction Cost                    22892     5888     2630    31410
   Contingency Allowance                 4418      589      263     5270
   Overhead Allowance                     683      583      260     1526
   Interest During Const.                 938       85       79     1103
   Total Capital Cost                   28931     7144     3233    39309
   Cost per KiloWatt ($/KW)              2893      714      323     3931

Annual Cost Summary (K$)               Gener.   Trans.   Subst.    Total
   Capital Recovery                      1996      519      235     2749
   Operation & Maintenance               1790      123       23     1936
   School Taxes                           268      110       49      427
   Fuel Costs                            4938        0        0     4938
   Total Annual Cost                     8991      752      307    10050
   Cost per KW.h (mills/kW.h)          197.43    16.52     6.75   220.69
```

8%
NET
DISCOUNT RATE

```
Capital Cost Summary (K$)              Gener.   Trans.   Subst.    Total
   Construction Cost                    22992     5888     2630    31410
   Contingency Allowance                 4418      589      263     5270
   Overhead Allowance                     683      583      260     1526
   Interest During Const.                1254      113      106     1473
   Total Capital Cost                   29247     7173     3259    39679
   Cost per KiloWatt ($/KW)              2925      717      326     3968

Annual Cost Summary (K$)               Gener.   Trans.   Subst.    Total
   Capital Recovery                      2509      637      290     3436
   Operation & Maintenance               1790      123       23     1936
   School Taxes                           268      110       49      427
   Fuel Costs                            4938        0        0     4938
   Total Annual Cost                     9505      870      362    10737
   Cost per KW.h (mills/kW.h)          208.71    19.11     7.95   235.77
```

TABLE A-6

Project Evaluation Package SEP 24 1984

Project Data For: GCI BIOMASS THERMAL

Project Capability
Peak Capacity (MW) 10.00
Firm Energy (GW.h) 45.54
Secondary Energy (GW.h) .00

Unit Fuel Cost ($/GJ) ==> .00
($/tonne) ==> 61.33
Calorific Value (MJ/Kg) ==> 20.00

Heat Rate (GJ/GWh) ==> 21600.00
Efficiency (%) ==> .00

Break Even
Fuel Cost

Fuel Cost (mills/kW.h) ==> 66.24
Fuel Consumption (kt/a) ==> 49.18

4%
NET
DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	22892	5888	2630	31410
Contingency Allowance	4418	589	263	5270
Overhead Allowance	683	583	260	1526
Interest During Const.	624	56	53	734
Total Capital Cost	28617	7116	3206	38940
Cost per KiloWatt ($/KW)	2862	712	321	3894

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	1533	412	185	2130
Operation & Maintenance	1790	123	23	1936
School Taxes	268	110	49	427
Fuel Costs	3016	0	0	3016
Total Annual Cost	6607	645	258	7509
Cost per KW.h (mills/kW.h)	145.08	14.16	5.66	164.90

With 20% Fire Grant

Unit Fuel Cost ($/GJ) ==> .00
($/tonne) ==> 67.41
Calorific Value (MJ/Kg) ==> 20.00

Heat Rate (GJ/GWh) ==> 21600.00
Efficiency (%) ==> .00

Break Even
Fuel Cost

Fuel Cost (mills/kW.h) ==> 72.80
Fuel Consumption (kt/a) ==> 49.18

4%
NET
DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	22759	5888	2630	31277
Contingency Allowance	0	589	263	852
Overhead Allowance	569	583	260	1412
Interest During Const.	520	56	53	630
Total Capital Cost	23848	7116	3206	34171
Cost per KiloWatt ($/KW)	2385	712	321	3417

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	1278	412	185	1875
Operation & Maintenance	1791	123	23	1937
School Taxes	223	110	49	382
Fuel Costs	3315	0	0	3315
Total Annual Cost	6607	645	258	7509
Cost per KW.h (mills/kW.h)	145.08	14.16	5.66	164.90

TABLE A-6 (continued)

```
                    Project Evaluation Package            SEP 20 1984

Project Data For:        GCI BIOMASS THERMAL

Project Capability
   Peak Capacity       (MW)           10.00
   Firm Energy        (GW.h)          45.54
   Secondary Energy   (GW.h)            .00

Unit Fuel Cost    ($/GJ) ==>            .00
              ($/tonne) ==>           52.77
Calorific Value (MJ/Kg) ==>           20.00

Heat Rate       (GJ/GWh) ==>       21600.00
Efficiency           (%) ==>            .00

Fuel Cost  (mills/kW.h) ==>           56.99
Fuel Consumption (kt/a) ==>           49.18
```

Break Even
Fuel Cost

6%
NET
DISCOUNT RATE

```
Capital Cost Summary (K$)                Gener.   Trans.   Subst.   Total
   Construction Cost                      22892     5888     2630   31410
   Contingency Allowance                   4418      589      263    5270
   Overhead Allowance                       683      583      260    1526
   Interest During Const.                   938       85       79    1103
   Total Capital Cost                     28931     7144     3233   39309
   Cost per KiloWatt ($/KW)                2893      714      323    3931

Annual Cost Summary (K$)                 Gener.   Trans.   Subst.   Total
   Capital Recovery                        1996      519      235    2749
   Operation & Maintenance                 1790      123       23    1936
   School Taxes                             268      110       49     427
   Fuel Costs                              2595        0        0    2595
   Total Annual Cost                       6648      752      307    7708
   Cost per KW.h (mills/kW.h)            145.99    16.52     6.75  169.25
```

```
Unit Fuel Cost    ($/GJ) ==>            .00
              ($/tonne) ==>           43.16
Calorific Value (MJ/Kg) ==>           20.00

Heat Rate       (GJ/GWh) ==>       21600.00
Efficiency           (%) ==>            .00

Fuel Cost  (mills/kW.h) ==>           46.61
Fuel Consumption (kt/c) ==>           49.18
```

Break Even
Fuel Cost

8%
NET
DISCOUNT RATE

```
Capital Cost Summary (K$)                Gener.   Trans.   Subst.   Total
   Construction Cost                      22892     5888     2630   31410
   Contingency Allowance                   4418      589      263    5270
   Overhead Allowance                       683      583      260    1526
   Interest During Const.                  1254      113      106    1473
   Total Capital Cost                     29247     7173     3259   39679
   Cost per KiloWatt ($/KW)                2925      717      326    3968

Annual Cost Summary (K$)                 Gener.   Trans.   Subst.   Total
   Capital Recovery                        2509      637      290    3436
   Operation & Maintenance                 1790      123       23    1936
   School Taxes                             268      110       49     427
   Fuel Costs                              2123        0        0    2123
   Total Annual Cost                       6690      870      362    7922
   Cost per KW.h (mills/kW.h)            146.89    19.11     7.55  173.95
```

TABLE A-7

Project Evaluation Package SEP 20 1934

Project Data For: QCI WOOD GAS

Project Capability
Peak Capacity (MW) 10.28
Firm Energy (GW.h) 45.54
Secondary Energy (GW.h) .00
Unit Fuel Cost ($/GJ) ==> .00
($/tonne) ==> 31.10
Calorific Value (MJ/Kg) ==> 20.00

Heat Rate (GJ/GWh) ==> 20000.00
Efficiency (%) ==> .00

Fuel Cost (mills/kW.h) ==> 31.10
Fuel Consumption (kt/a) ==> 45.54

Scenario III
Fuel Cost

4% NET DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	28280	5288	2630	36798
Contingency Allowance	5532	589	263	6383
Overhead Allowance	845	583	260	1689
Interest During Const.	773	56	53	882
Total Capital Cost	35430	7116	3206	45752
Cost per KiloWatt ($/KW)	3446	692	312	4451

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	1898	412	185	2495
Operation & Maintenance	1790	123	23	1936
School Taxes	331	110	49	491
Fuel Costs	1416	0	0	1416
Total Annual Cost	5436	645	258	6338
Cost per KW.h (mills/kW.h)	119.37	14.16	5.66	139.18

6% NET DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	28280	5888	2630	36798
Contingency Allowance	5532	589	263	6383
Overhead Allowance	845	583	260	1689
Interest During Const.	1162	85	79	1326
Total Capital Cost	35519	7144	3233	46196
Cost per KiloWatt ($/KW)	3484	695	314	4494

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	2471	519	235	3224
Operation & Maintenance	1790	123	23	1936
School Taxes	331	110	49	491
Fuel Costs	1416	0	0	1416
Total Annual Cost	6005	752	307	7068
Cost per KW.h (mills/kW.h)	131.93	16.52	6.75	155.20

8% NET DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	28280	5888	2630	36798
Contingency Allowance	5532	589	263	6383
Overhead Allowance	845	583	260	1689
Interest During Const.	1553	113	106	1771
Total Capital Cost	36209	7173	3259	46641
Cost per KiloWatt ($/KW)	3522	698	317	4537

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	3107	637	290	4034
Operation & Maintenance	1790	123	23	1936
School Taxes	331	110	49	491
Fuel Costs	1416	0	0	1416
Total Annual Cost	6645	870	362	7877
Cost per KW.h (mills/kW.h)	145.91	19.11	7.95	172.96

TABLE A-8

```
                         Project Evaluation Package              SEP 20 1984

   Project Data For:         QCI WOOD GAS

   Project Capability
      Peak Capacity       (MW)            10.28
      Firm Energy        (GW.h)           45.54
      Secondary Energy   (GW.h)             .00
 Unit Fuel Cost   ($/GJ) ==>                .00
              ($/tonne) ==>              153.46
 Calorific Value (MJ/Kg) ==>              20.00

 Heat Rate      (GJ/GWh) ==>           20000.00
 Efficiency          (%) ==>                .00

 Fuel Cost  (mills/kW.h) ==>             153.46
 Fuel Consumption (kt/a) ==>              45.54
```

Scenario IV
Fuel Cost

4%
NET
DISCOUNT RATE

```
Capital Cost Summary (K$)                Gener.   Trans.   Subst.   Total
   Construction Cost                      28280     5888     2630    36798
   Contingency Allowance                   5532      589      263     6383
   Overhead Allowance                       845      583      260     1689
   Interest During Const.                   773       56       53      882
   Total Capital Cost                     35430     7116     3206    45752
   Cost per KiloWatt ($/KW)                3446      692      312     4451

Annual Cost Summary (K$)                 Gener.   Trans.   Subst.   Total
   Capital Recovery                        1898      412      185     2495
   Operation & Maintenance                 1790      123       23     1936
   School Taxes                             331      110       49      491
   Fuel Costs                              6989        0        0     6989
   Total Annual Cost                      11008      645      258    11911
   Cost per KW.h (mills/kW.h)            241.73    14.16     5.66   261.54
```

6%
NET
DISCOUNT RATE

```
Capital Cost Summary (K$)                Gener.   Trans.   Subst.   Total
   Construction Cost                      28280     5888     2630    36798
   Contingency Allowance                   5532      589      263     6383
   Overhead Allowance                       845      583      260     1689
   Interest During Const.                  1162       85       79     1326
   Total Capital Cost                     35819     7144     3233    46196
   Cost per KiloWatt ($/KW)                3484      695      314     4494

Annual Cost Summary (K$)                 Gener.   Trans.   Subst.   Total
   Capital Recovery                        2471      519      235     3224
   Operation & Maintenance                 1790      123       23     1936
   School Taxes                             331      110       49      491
   Fuel Costs                              6989        0        0     6989
   Total Annual Cost                      11581      752      307    12640
   Cost per KW.h (mills/kW.h)            254.29    16.52     6.75   277.56
```

8%
NET
DISCOUNT RATE

```
Capital Cost Summary (K$)                Gener.   Trans.   Subst.   Total
   Construction Cost                      28280     5888     2630    36798
   Contingency Allowance                   5532      589      263     6383
   Overhead Allowance                       845      583      260     1689
   Interest During Const.                  1553      113      106     1771
   Total Capital Cost                     36209     7173     3259    46641
   Cost per KiloWatt ($/KW)                3522      698      317     4537

Annual Cost Summary (K$)                 Gener.   Trans.   Subst.   Total
   Capital Recovery                        3107      637      290     4034
   Operation & Maintenance                 1790      123       23     1936
   School Taxes                             331      110       49      491
   Fuel Costs                              6989        0        0     6989
   Total Annual Cost                      12217      870      362    13449
   Cost per KW.h (mills/kW.h)            268.27    19.11     7.95   295.32
```

TABLE A-9

Project Evaluation Package SEP 20 1984

Project Data For: QCI WOOD GAS

Project Capability	
Peak Capacity (MW)	10.28
Firm Energy (GW.h)	45.54
Secondary Energy (GW.h)	.00
Unit Fuel Cost ($/GJ) ==>	.00
($/tonne) ==>	100.40
Calorific Value (MJ/Kg) ==>	20.00
Heat Rate (GJ/GWh) ==>	20000.00
Efficiency (%) ==>	.00
Fuel Cost (mills/kW.h) ==>	100.40
Fuel Consumption (kt/a) ==>	45.54

Base Case
Scenario III
Fuel Cost

4%
NET
DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	28280	5888	2630	36798
Contingency Allowance	5532	589	263	6383
Overhead Allowance	845	583	260	1689
Interest During Const.	773	56	53	882
Total Capital Cost	35430	7116	3206	45752
Cost per KiloWatt ($/KW)	3446	692	312	4451

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	1898	412	185	2495
Operation & Maintenance	1790	123	23	1936
School Taxes	331	110	49	491
Fuel Costs	4572	0	0	4572
Total Annual Cost	8592	645	258	9494
Cost per KW.h (mills/kW.h)	188.67	14.16	5.66	208.48

6%
NET
DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	28280	5888	2630	36798
Contingency Allowance	5532	589	263	6383
Overhead Allowance	845	583	260	1689
Interest During Const.	1162	85	79	1326
Total Capital Cost	35819	7144	3233	46196
Cost per KiloWatt ($/KW)	3484	695	314	4494

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	2471	519	235	3224
Operation & Maintenance	1790	123	23	1936
School Taxes	331	110	49	491
Fuel Costs	4572	0	0	4572
Total Annual Cost	9164	752	307	10224
Cost per KW.h (mills/kW.h)	201.23	16.52	6.75	224.50

8%
NET
DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	28280	5888	2630	36798
Contingency Allowance	5532	589	263	6383
Overhead Allowance	845	583	260	1689
Interest During Const.	1553	113	106	1771
Total Capital Cost	36209	7173	3259	46641
Cost per KiloWatt ($/KW)	3522	698	317	4537

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	3107	637	290	4034
Operation & Maintenance	1790	123	23	1936
School Taxes	331	110	49	491
Fuel Costs	4572	0	0	4572
Total Annual Cost	9801	870	362	11033
Cost per KW.h (mills/kW.h)	215.21	19.11	7.95	242.26

TABLE A-10

```
                         Project Evaluation Package           SEP 24 1984

      Project Data For:       QCI WOOD GAS

      Project Capability
         Peak Capacity      (MW)           10.28
         Firm Energy       (GW.h)          45.54
         Secondary Energy  (GW.h)            .00


     Unit Fuel Cost   ($/GJ) ==>             .00
                  ($/tonne) ==>            56.82
     Calorific Value (MJ/Kg) ==>           20.00

     Heat Rate      (GJ/GWh) ==>        20000.00
     Efficiency          (%) ==>             .00

     Fuel Cost  (mills/kW.h) ==>           56.82
     Fuel Consumption (kt/a) ==>           45.54
```

Break Even
Fuel Cost

```
              Capital Cost Summary (K$)            Gener.   Trans.   Subst.   Total
                 Construction Cost                  28280     5888     2630   36798
                 Contingency Allowance               5532      589      263    6383
                 Overhead Allowance                   845      583      260    1689
                 Interest During Const.               773       56       53     882
                 Total Capital Cost                 35430     7116     3206   45752
                 Cost per KiloWatt ($/KW)            3446      692      312    4451

              Annual Cost Summary (K$)             Gener.   Trans.   Subst.   Total
                 Capital Recovery                    1898      412      185    2495
                 Operation & Maintenance             1790      123       23    1936
                 School Taxes                         331      110       49     491
                 Fuel Costs                          2588        0        0    2588
                 Total Annual Cost                   6607      645      258    7510
                 Cost per KW.h (mills/kW.h)        145.09    14.16     5.66  164.90
```

4%
NET
DISCOUNT RATE

```
     Unit Fuel Cost   ($/GJ) ==>             .00
                  ($/tonne) ==>            45.15
     Calorific Value (MJ/Kg) ==>           20.00

     Heat Rate      (GJ/GWh) ==>        20000.00
     Efficiency          (%) ==>             .00

     Fuel Cost  (mills/kW.h) ==>           45.15
     Fuel Consumption (kt/a) ==>           45.54
```

Break Even
Fuel Cost

```
              Capital Cost Summary (K$)            Gener.   Trans.   Subst.   Total
                 Construction Cost                  28280     5888     2630   36798
                 Contingency Allowance               5532      589      263    6383
                 Overhead Allowance                   845      583      260    1689
                 Interest During Const.              1162       85       79    1326
                 Total Capital Cost                 35819     7144     3233   46196
                 Cost per KiloWatt ($/KW)            3484      695      314    4494

              Annual Cost Summary (K$)             Gener.   Trans.   Subst.   Total
                 Capital Recovery                    2471      519      235    3224
                 Operation & Maintenance             1790      123       23    1936
                 School Taxes                         331      110       49     491
                 Fuel Costs                          2056        0        0    2056
                 Total Annual Cost                   6648      752      307    7708
                 Cost per KW.h (mills/kW.h)        145.98    16.52     6.75  169.25
```

6%
NET
DISCOUNT RATE

TABLE A-10 (continued)

Project Evaluation Package SEP 20 1984

Project Data For: GCI WOOD GAS

Project Capability		
Peak Capacity	(MW)	10.28
Firm Energy	(GW.h)	45.54
Secondary Energy	(GW.h)	.00

Unit Fuel Cost	($/GJ) ==>	.00
	($/tonne) ==>	32.09
Calorific Value	(MJ/Kg) ==>	20.00
Heat Rate	(GJ/GWh) ==>	20000.00
Efficiency	(%) ==>	.00
Fuel Cost	(mills/kW.h) ==>	32.09
Fuel Consumption	(kt/a) ==>	45.54

Break Even
Fuel Cost

8%
NET
DISCOUNT RATE

Capital Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Construction Cost	28280	5888	2630	36798
Contingency Allowance	5532	589	263	6383
Overhead Allowance	845	583	260	1689
Interest During Ccnst.	1553	113	106	1771
Total Capital Cost	36209	7173	3259	46641
Cost per KiloWatt ($/KW)	3522	698	317	4537

Annual Cost Summary (K$)	Gener.	Trans.	Subst.	Total
Capital Recovery	3107	637	290	4034
Operation & Maintenance	1790	123	23	1936
School Taxes	331	110	49	491
Fuel Costs	1461	0	0	1461
Total Annual Cost	6690	870	362	7922
Cost per KW.h (mills/kW.h)	146.90	19.11	7.95	173.95